JOINT IMPLEMENTATION PROJECT DESIGN DOCUMENT FORM
Version 01 - in effect as of: 15 June 2006

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Annexes

Attachments

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SECTION A. General description of the project

A.1. Title of the project:

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SNG gas gathering
Version 05, 16 January 2009

A.2. Description of the project:

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Purpose:
The purpose of JSC TNK-BP Holding's (TNK-BP's) proposed JI project is to recover and market low-pressure (LP) associated petroleum gases (APG) that is currently being flared from the last stages of separation at oil treatment sites within the Samotlor oilfield, thereby reducing flaring of APG in the oilfield and emissions of GHG to the atmosphere.

Current status:
Samotlor oilfield is a large reservoir discovered by Soviet geologists in Nizhnevartovsk region in the early 1960s, and the first producing well was drilled in 1969. Eleven years later, Samotlor reached its peak production level of nearly 3.2 million barrels per day and has since declined to about 400 000 barrels per day. New technology and updated forecasts of future reserves indicate about 7 billion barrels of oil and 100 BCM of gas in place. The Samotlor oilfield is operated by a fully owned subsidiary of TNK-BP; JSC "Samotlorneftegaz" (SNG).

While treating oil at Samotlor oil treatment sites, some associated gas produced at 1st and 2nd stages of oil separation is currently utilized for internal needs by TNK-BP as fuel for boilers to generate thermal energy as well as working agent for gas lift production[1]. Some gas is gathered and transported to gas processing plant for sale, while the residual gas is flared on-site. Non-compressed APG is transported via LP pipelines from the 1st stage of oil separation. At some sites, gas from the 2nd and final stages of oil separation is transported after oil treatment by using Vacuum Compressor Stations[2] (VCSs). Other sites currently lack infrastructure (specifically VCSs) to recover and compress gas from the last stages of oil separation. For those oil treatment sites that are lacking VCSs, gas from the 2nd and final stages of separation is flared in the course of the oil treatment process.

Flaring of LP APG originating from the last stages of separation from the five oil treatment sites covered in this PDD, all lacking VCSs, is estimated at 0.25 million cubic meters (MMCM) per day, equivalent to 90 MMCM per year. This gas is flared it has insufficient pressure and has too high liquid content to be transported in existing gas infrastructure. VCSs can be installed to collect and compress the gas coming from the last stages of oil separation and allow for transportation of the recovered gas into an export pipeline. Installation of VCSs is the preferred techno-economic solution to reduce flaring of this source of APG, but due to the high cost of installation and operation and the limited value of the recovered gas the economic returns earned by the project developer for implementing the proposed project is not sufficient to justify the investment.

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[1] 4.2 BCMA is circulating in the gas lift system.

[2] A VCS is a point of collection and compression of gas coming from the last stages of oil separation and transportation of the recovered gas into an export pipeline. It is designed to guarantee uninterrupted collection of gas. The collected gas is passed through one or more separators where liquids are dropped out (i.e. drop-out precipitate), and the gas is then compressed to the required pressure level for injection into a pipeline system. See Section A.4.2 for more information.

Project activity:
The proposed JI project activity consists of installation and operation of five VCSs at distinct oil treatment sites within Samotlor oilfield to facilitate recovery of LP APG from the last stages of oil separation. The SNG gas gathering project will result in recovery of 90 MMCM per year of APG that will be transported to market in existing LP gas pipelines and production of about 7,000 t per year of stable hydrocarbon condensate (i.e. drop-out precipitate) that will be delivered to the oil gathering system at the oil treatment sites.

Successful implementation of the proposed JI project activity is expected to reduce flaring of APG at the relevant oil treatment sites within the Samotlor oilfield to an operational minimum and thus substantially reduce emissions of GHG to the atmosphere.

Contribution to sustainable development:
The proposed JI project activity will contribute positively to sustainable development as following:

- Low-pressure associated gas currently flared on-site will be used productively and provide economic benefits;
- Local production, distribution and sale of gas and gas liquids will create local employment opportunities downstream the gas value chain;
- Minimization of the flaring of APG will both contribute to mitigate the effect of climate change and reduce emissions of particulates at the local level.

A.3. Project participants:

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Name of Party involved (*) ((host) indicates a host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Russian Federation (host)	JSC TNK-BP Holding JSC Samotlorneftegaz	No No
To be determined	Carbon Limits AS	No

A.4. Technical description of the project:

A.4.1. Location of the project:

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A.4.1.1. Host Party(ies):

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The Russian Federation

A.4.1.2. Region/State/Province etc.:

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West Siberia, Khanty-Manskiysky Autonomous Okrug

A.4.1.3. City/Town/Community etc.:

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15 km from Nizhnevartovsk city

A.4.1.4. Detail of physical location, including information allowing the unique identification of the project (maximum one page):

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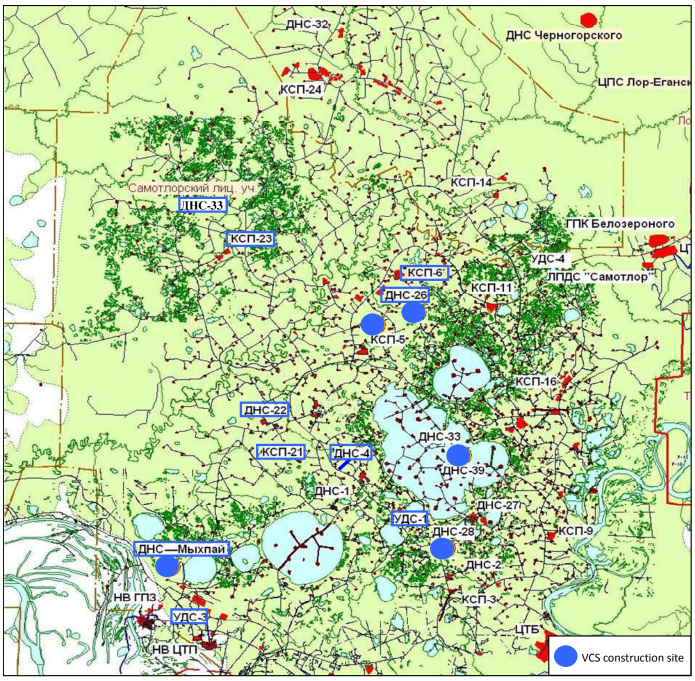
The Samotlor oilfield is located in Western Siberia in the surroundings of Lake Samotlor in Urals Federal District. The centre of the Samotlor oil field is situated about 20 km north east from the city of Nizhnevartovsk. Geographical coordinates for the Samotlor Oil Field are: 60°58’00 N, 76°48’00 E.

Figure 1: Map of Russian Federation indicating the location of the Samotlor Oil Field

The exact locations of the five VCSs to be installed as part of the project activity within the Samotlor oilfield are:



A.4.2. Technology(ies) to be employed, or measures, operations or actions to be implemented by the project:

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The proposed JI project activity consists of installation of five VCSs at specific oil production sites within Samotlor oilfield. A VCS collects and compresses gas coming from the last stages of oil separation and allows for transportation of the recovered gas into an export pipeline.

General functionality of a VCS:

A VCS is designed for:

- Guaranteeing uninterrupted collection of gas from the last stages of oil separation
- Additional separation of the gas (i.e. drop-out precipitate)
- Compression of the gas to the required pressure level
- Transportation of the compressed gas into a pipeline system
- Metering of the gas and any other products (i.e. precipitate) leaving the VCS

There are minor site specific variations between the designs of the five VCSs that will be installed (i.e. operating conditions and dimensions) as part of the proposed JI project activity; however the basic design and function is uniform for all five facilities. In this PDD, the general functionality of a VCS is illustrated in terms of the design developed for the VCS to be installed at BPS-Mykhpay (one of the five VCSs):

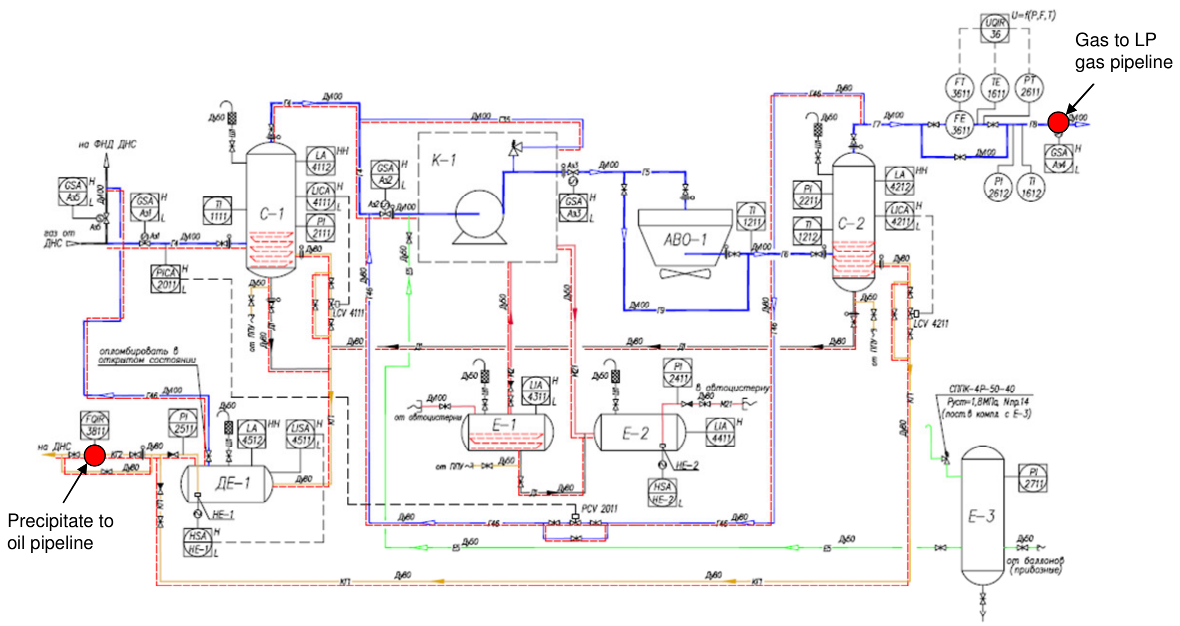

Figure 2: Technical schematic of VCS Mykhpay illustrating metering points

Brief description of physical flows and installed equipment (ref. Figure 2):

APG from the last stages of oil separation is transported to the first gas separator (C-1) at a pressure of less than 0.05 atm. The gas separated out in the separator is transported to the compressor (K-1), while removed liquids (precipitate) are dropped into the drainage drum (ДE-1) for temporary storage. Stored liquids are pumped out through the measuring device (FQIR 3811) into the existing oil pipeline for export at regular intervals. The level of precipitate in separator C-1 is regulated by a control valve (LISA 4511) that controls the operation of the liquid pump (HE-1).

The gas entering compressor K-1 is compressed to 6.9 atm and will then have a temperature of about 100^0C. The gas is cooled in an air cooler (ABO-1), where the temperature is dropped to 40^0C before the gas is sent to separator S-2 with further separation of condensates/precipitate as a result of cooling of the gas. The gas separated out in separator S-2 is transported through a measuring device (FE 3611) into the existing low pressure gas pipeline(s), while removed liquids (precipitate) are dropped into the drainage drum (ДЕ-1) for temporary storage.

The compressor system is supplied by an oil regeneration system consisting of a clean oil container (E-1) a waste oil container (E-2) and necessary piping and control systems to operate the system. A nitrogen receiver (E-3) is also installed and filled with imported balloons for the scavenging of compressor lines.

In case of emergencies and shut-down of the compressor station, pipelines are installed to bypass the VCS. The APG would in case of emergency be flared at the oil separation station (similar to the current practice). To ensure proper operations during winter months, electric heating circuits are installed on all critical equipment items (e.g. oil lines, drainage lines, gas pipes and emergency discharge lines).

Physical layout:
The physical area of each VCS is divided into three zones; (1) technical zone, (2) production support zone, and (3) general support zone. The technical zone comprises all production equipment and auxiliary units, e.g. the separators, the compressor, the air cooler and the precipitate container. The production support zone contains the pumping station, the oil regeneration system and the nitrogen receiver. The general support zone contains the control room and the living quarters. All data metered in the VCS are transferred electronically to the control room, where the operator(s) can collect, evaluate and act upon real-time operational data. The three zones are divided by intra-area roads and communication corridors.

Suppliers:
Contractors and suppliers will be selected among those who have been prequalified and comply with TNK-BP's HSE requirements, technical standards and other parameters regarding the quality of work to be performed, such as TNK-BP best practice requirements and other indicators consistent with the targets and objectives set.

A.4.3. Brief explanation of how the anthropogenic emissions of greenhouse gases by sources are to be reduced by the proposed JI project, including why the emission reductions would not occur in the absence of the proposed project, taking into account national and/or sectoral policies and circumstances:

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The purpose of TNK-BP's proposed JI project is to recover and market LP APG from the last stages of separation at oil treatment sites within the Samotlor oilfield that is currently being flared, thereby reducing flaring of APG in the oilfield and emissions of GHG to the atmosphere.

The project activity consists of building and operating five VCSs at specific oil treatment sites to recover about 90 MMCM of APG per year. Currently the APG has a pressure level insufficient for transportation in existing gas infrastructure and contains considerable natural gas liquids which prevent its transportation. After installation of the VCSs, the APG that is currently flared can be prepared for transportation in pipelines by separating out heavy precipitate and compressing it to a pressure level sufficient for injection into the existing gas export pipelines.

After implementation of the project activity, flaring of gas from the sources included in the project boundary will be reduced to the operational minimum (i.e. operational flares and flaring due to imbalances in the gas value chain). The flaring of LP APG from the last stages of oil separation will essentially be eliminated as long as there are no downstream bottlenecks in processing and/or marketing channels that prohibit the marketing of this source of gas. Given the capacity situation in the downstream gas value chain, such bottlenecks would be the result of unpredictable emergency cases like shut-down of one of the regional GPPs[3].

The effect of the project activity, the installation of five VCSs, is increased productive use of APG and thereby a significant and measurable reduction of flaring and thus GHG emissions from TNK-BP's operations at Samotlor oilfield.

In the absence of the proposed project activity, the most economic alternative for TNK-BP would be to continue to flare the APG from the final stages of oil separation at the five oil treatment sites. The ability to register the project as a JI project and monetize the resulting GHG emission reductions provides an essential incentive to implement the project.

APG flaring in Russia:
In 2006, the US National Oceanic and Atmospheric Administration (NOAA) estimated that Russia flared approximately 52 BCM/yr of gas, up from a figure of 37 BCM/yr in 1996. The Russian Ministry of Industry and Energy has recognized that oil and gas companies in Russia produced 55 BCM associated gas in 2005, of which 40 BCM was vented or flared. Other Russian sources state that the gas flaring levels are around half this figure. Still, at the lower level of 25 BCM/yr, Russia flares more associated gas than any other country.

The utilization of associated gas in Russia is therefore relatively low, and this is primarily due to physical and economic barriers. Historically, Russian oil companies have had little incentive to recover and utilize associated petroleum gases. This has partly been related to the availability of relatively low-cost non-associated natural gas to serve as the principal and lowest cost source of gas supply. As a result of the relative abundance of non-associated gas and their distance from markets and/or infrastructure, some oil fields have been developed without the infrastructure to recover and utilize APG due to significantly higher investment costs.

The great distance to market is a significant barrier to investment in gas infrastructure. Most Russian oil producing regions have sparse populations and little local demand. Small volumes can be used locally, if there is local demand, but larger volumes need to be shipped off, and given the distances, pipelines constitute the only realistic alternative.

Currently, no secondary legislation (such as codes, guidelines) exists at the federal level that deals specifically with operational processes or regulatory procedures related to gas flaring and venting. Government Resolution N 344 of June 12, 2003, updated by the Government Resolution N 410 of July 1, 2005 introduces taxes on emissions of environmentally damaging substances. The list includes methane, SO_X, NO_X, sulfur, and ashes, but not CO_2. These taxes apply for each harmful pollutant depending on whether the operator stays within "established emission limits"[4], within "temporarily agreed emission limits" or "above-limit emissions". Methane is the main pollutant relevant to flaring of APG. The tax rates for methane contained in APG flared by stationary sources[5] are 50 roubles/tonne (USD 2/tonne), 250 roubles/tonne (USD 10/tonne) or 1250 roubles/tonne (USD 50/tonne) respectively.

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[3] The Belozerniy GPP was shut down for a period of 11 months in 2007/8 (5 May 2007 to 1 April 2008) due to an unpredictable explosion in one of the processing trains.

[4] The Maximum Permissible Concentration (MPC) of emissions is established by the Ministry of Health.

[5] The tax is applicable for methane emissions resulting from incomplete combustion of APG in stationary sources (e.g. flares).

With the current taxation of emissions companies have limited direct fiscal incentives to increase utilization of associated gas, apart from the value of the gas itself and taxes on incomplete combustion of methane.

In a public address in April 2007, the President of the Russian Federation named APG flaring as one of the main problems facing Russia's energy industry. Despite high economic losses and increasing concerns at the highest political level, substantial improvements in the Russian regulatory framework and national policies have yet to be substantially improved to stimulate more effective usage of APG and create the necessary conditions for a significant reduction in flaring. Plans to increase the regulated wholesale prices for APG and flaring fees have been announced recently, but even with stronger economic incentives in place it is not expect to reach the government's objective of 95%-rate of utilization for APG before 2015[6]. The JI Mechanism could provide an effective incentive to help reach this stated objective.

It can therefore be concluded that flaring is common practise in Russia, and APG recovery remains relatively low.

Conclusion on why the emission reduction would not occur in the absence of the project activity:
Associated gas is increasingly recognized to be of considerable economic value, and TNK-BP has put considerable efforts into exploring, assessing and implementing optimal options for utilizing APG. The company launched an APG resource audit program in 2005, and came up with recommended options to optimize the APG collection and transportation system operations in several regions.

In addition to several economically interesting alternatives to increase utilization of APG that were identified as part of the company wide APG resource audit, other marginally attractive investment opportunities were also identified. These marginally attractive investment opportunities to increase utilization of APG typically comprise projects with limited volumes of recoverable APG, long distance transportation to end-consumers, expensive gas gathering and processing solutions and low value of marketable products. It is these projects that are viewed as relevant for JI.

This proposed JI project activity represents an interesting opportunity to further increase utilization of APG from the last stages of separation at oil treatment sites within the Samotlor oilfield and thus reduce flaring to an operational minimum. However, the project does not, in and of itself, make economic sense for the developer. The implementation of the proposed JI project faces significant economic barriers and would not be implemented without the contribution of the JI component (see Section B.2 for further information about the economic attractiveness of the project activity).

Carbon finance will contribute to the implementation of a relatively expensive measure to eliminate a substantial source of flaring at SNG, clearly contributing to the objective of the national energy strategy. The project will recover and utilize a valuable energy resource that would otherwise be wasted. The project will also lead to a reduction in regional volumes of gas flaring and will allow significant mitigation of local polluting emissions.

A.4.3.1. Estimated amount of emission reductions over the crediting period:

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Years	**Annual estimation of emission reductions in tonnes of CO_{2e}**
2009 (Q2-Q4)	169,249
2010	225,666

6 http://www.lawtek.ru/news/tek/40363.html

2011	225,666
2012	225,666
2013	225,666
2014	225,666
2015	225,666
2016	225,666
2017	225,666
2018	225,666
2019 (Q1)	56,416
Total estimated reductions for crediting period 01 Apr 2009 to 31 Mar 2019 (tonnes of CO_{2e})	**2,256,657**
Total estimated reductions for the period 01 Apr 2009 to 31 Dec 2012 (tonnes of CO_{2e})	**846,246**
Annual average over the crediting period of estimated reductions (tonnes of CO_{2e})	**225,666**

The crediting period of the JI project starts on 01 April 2009 and ends on 31 March 2019.

Crediting of the project with ERUs after 2012 is dependent on approval by the host party, the Russian Federation.

During the part of the crediting period equalling the first commitment period, the project will generate emission reductions estimated to be 846,246 tonnes of CO_2 equivalent (for the period from 01 Apr 2009 to 31 December 2012), which is sought being rewarded with ERUs.

During the part of the crediting period beyond the first commitment period, emission reductions generated by the project are estimated to be 1,410,411 tonnes of CO_2 equivalent, which will be sought rewarded with emission reduction credits pending regulatory framework for generation and transfer of emission reductions post 2012.

A.5. Project approval by the Parties involved:

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Approvals by the Russian and other Annex B country UNFCC Focal Points are pending.

SECTION B. Baseline

B.1. Description and justification of the baseline chosen:

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The baseline for a JI project is the scenario that reasonably represents the anthropogenic emissions by source or anthropogenic emissions by sinks of GHGs that would occur in the absence of the proposed project.

The baseline of this PDD is established on a project-specific basis with respect to the requirements of the JI guidelines as specified in the *"Guidance on criteria for baseline setting and monitoring (version 01)"*. In doing so, the approved CDM baseline and monitoring methodology AM0009 *"Recovery and utilization of gas from oil wells that would otherwise be flared"* is applied in accordance with the provisions made in option 20 (a) of the JI guidelines. All explanations, descriptions and analysis related to the identification of a baseline are made following the chosen methodology.

Evaluate legal aspects:
As specified in AM0009, the baseline is selected based on legal applicability and economic analysis of alternatives. Thus, the baseline represents utilization of a technology that represents a preferred course of action taking into account barriers to investment. It will be demonstrated below that continued flaring of APG in five specific sites in the Samotlor oil field is the baseline scenario.

The approach selected allows for a transparent determination of the baseline with regard to the choice of approaches, assumptions, parameters, data sources and key factors. Uncertainties are accounted for in accordance with AM0009, i.e. by utilizing conservative assumptions.

For the selection of a baseline scenario and demonstration and assessment of additionality, version 03.2 of AM0009 is applied.

Demonstration of applicability of the selected CDM methodology (AM0009 - version 03.2):
The selected CDM methodology is applicable to project activities that recover and utilize associated gas that was previously flared or vented from oil wells. In addition, the JI project has to meet the following applicability conditions:

1. Associated gas at oil wells is recovered and transported to:
    a. A processing plant where dry gas, liquefied petroleum gas (LPG), and condensate are produced; and/or,
    b. An existing natural gas pipeline without processing.
2. All associated gas recovered comes from oil wells that are in operation and are producing oil at the time of the recovery of the associated gas;
3. The recovered gas and the products (dry gas, LPG and condensate) are likely to substitute in the market only the same type of fuels or fuels with a higher carbon content per unit of energy;
4. The utilization of the associated gas due to the project activity is unlikely to lead to an increase of fuel consumption in the respective market;
5. The project activity does not lead to changes (negative or positive) in the volume or composition of oil or high-pressure gas extracted at the production site;
6. Data (quantity and fraction of carbon) are accessible on the products of the gas processing plant and on the gas recovered from other oil exploration facilities in cases where these facilities supply recovered gas to the same gas processing plant;
7. No gas coming from a gas lift system is used by the project activity.

In addition, the applicability conditions included in the tools mentioned in AM0009 apply. The methodology is only applicable if the identified baseline scenario is the continuation of the current practice of either flaring or venting of the associated gas.

The JI project meets the above mentioned applicability conditions as follows:

1. APG from oil wells is recovered from the last stages of oil separation at five oil treatment sites and transported to existing natural gas pipeline systems (Option 1.b).
2. All the APG recovered is produced from oil wells that are in operation at the time of recovery of the associated gas;
3. The recovered gas (and subsequent products thereof) is likely to substitute in the market the same type of fuels or fuels with higher carbon content per unit of energy. The products will compete with other suppliers in the domestic markets, and the small amounts added by the JI project activity will have no impact on the global markets in terms of price or inter-fuel competition.
4. The absolute amount of APG and precipitate marketed is not significant compared to the total size of the domestic markets. Between 7.8 and 9.1 BCM of dry gas is expected to be marketed from the two GPPs in the Nizhnevartovsk region annually, while the daily oil production from the Samotlor oilfield alone comprise almost 400,000 bbl per day. Due to the negligible volumes of recovered products marketed and the competition with alternative suppliers the project activity is thus not expected to lead to any increase of fuel consumption due to altering marketing conditions;
5. The proposed JI project activity will not affect the extraction of oil or high-pressure gas in Samotlor oil field. The project does not remove any constraints related to optimization of production from the field, and the value added by recovery and sale of APG and precipitate is negligible compared to the value of the overall production.
6. All data required for monitoring of the project in accordance with AM0009 will be readily available.
7. The APG recovered from the final stages of oil separation at the five oil treatment sites is not linked to the operation of the gas lift system of the Samotlor oilfield.

The procedure described in AM0009 version 03.2 to identify the baseline scenario and demonstrate additionality contains the following steps:

Step 1. *Identify plausible alternative scenarios*
Step 2. *Evaluate legal aspects*
Step 3. *Evaluate the economic attractiveness of alternatives*

The application of the procedure to identify the baseline scenario and demonstrate additionality specified in AM0009 demonstrates that the identified baseline scenario is the continuation of the current practice of flaring (see analysis below and in Section B.2). The proposed JI project activity is thus found to be applicable as specified in AM0009.

Identification of the baseline scenario

The identification of the baseline scenario is done by applying the procedure specified in AM0009 version 03.2 presented above.

Step 1: Identify plausible alternative scenarios

AM0009 lists seven plausible alternative scenarios for how associated gas is likely to be treated at oil fields. After applying the analytical steps proposed in the selected methodology to identify the baseline scenario, these alternative scenarios and their relevance to this project activity are:

Scenario 1: Release of the associated gas into the atmosphere at the oil production site (venting)

Venting of the gas in such quantities as produced at the five sites covered in this PDD would be extremely dangerous to the workers due to the likelihood of explosion at the risk of life and property and for environmental health by inhaling methane and other gases. This alternative has never been considered viable for these reasons and is not considered.

Scenario 2: Flaring of the LP associated gas at the oil production site

This is the scenario currently describing the situation at the five oil treatment sites covered by this PDD and represents the "business as usual" case. Substantial gas volumes are currently exported from the Samotlor oilfield and sold to the market, but utilization of LP APG from the last stages of oil separation at the five oil treatment sites covered in this PDD faces significant economic barriers due to the relatively low volumes of APG, the low pressure level of the gas, the high liquid content and the cost of the investment. Several VCSs have been installed in the Samotlor oilfield in the past based on site specific economic considerations and investment decisions, all pre-dating the establishment of TNK-BP as a company. Continued flaring of APG at the five oil treatment sites currently lacking VCSs represents the most economic alternative for TNK-BP.

Scenario 3: On-site use of the associated gas for power production

Some associated gas produced at 1st and 2nd stages of oil separation is currently utilized for internal needs as fuel for boilers to generate thermal energy as well as working medium for gas lift production. The majority of equipment installed in the Samotlor oilfield is operated by electricity purchased from the grid. Based on the quality of installed equipment and the geographical distribution of power consumers in the oilfield it has not been considered feasible to utilize additional volumes of APG for on-site power production. APG not required for boilers or gas lift is currently exported for external usage, and it is highly uneconomic to change this practice due to recovery of the relatively limited volumes of APG currently flared from the last stages of oil separation at oil treatment sites.

Scenario 4: On-site use of the associated gas for liquefied natural gas production

At this point in time there is no rationale to install any LNG facility as there is no market and the volumes are not sufficient to produce LNG. This alternative scenario has never been studied in detail as it is considered to be an unfeasible alternative by TNK-BP.

Scenario 5: Injection of the associated gas into an oil or gas reservoir

Excessive capital and operational expenditures to allow for a suitable gas injection scheme as well as uncertain reservoir performance prohibit such a development, and the alternative is considered to be very unattractive by the oil field operator. This is thus not considered to be a feasible option by TNK-BP experts, and this is justified by the fact that TNK-BP is currently not re-injecting any gas at Samotlor oilfield, neither for Enhanced Oil Recovery nor for temporal storage of gas.

Scenario 6: Recovery, transportation, processing and distribution of the associated gas and products thereof to end-users without being registered as a (JI) CDM project

Most of the APG from the Samotlor oilfield is already marketed through the existing pipeline system (see breakdown in Section A.2). Recently, regional processing capacity has been upgraded and in the near future there is expected to be spare capacity to handle additional volumes of gas. The ability to recover additional volumes of APG from the last stages of oil separation at oil treatment sites has thus become much easier from a technical standpoint.

This alternative is described in detail in this PDD. The proposed JI project is economically unattractive for the project developer without income from sale of ERUs, and is thus considered unfeasible without being registered as a JI project activity. The economic assessment of this alternative is presented in detail in Section B.2.

Scenario 7: Recovery, transportation and utilization of the associated gas as feedstock for manufacturing of a useful product

Based on the fact that there are no nearby industrial users nor markets for petrochemical products and that the volumes of recoverable APG are small, this is not an economically attractive scenario.

Step 2: Evaluate legal aspects

For each of the seven alternative scenarios specified above, an analysis has been made of the alternative's compliance with applicable legal and regulatory requirements in the Russian Federation:

Scenario 1: Release of the associated gas into the atmosphere at the oil production site (venting)

This alternative has never been considered viable and the legal aspects have thus not been evaluated.

Scenario 2: Flaring of the LP associated gas at the oil production site

Flaring is not prohibited in the Russian Federation, and this alternative is in compliance with all applicable legal and regulatory requirements. The Russian authorities impose a fine for emissions from stationary combustion (i.e. the flaring of gas), but in this instance the payment of the fine is economically preferable to investing in any other alternative.

Scenario 3: On-site use of the associated gas for power production

This alternative has not been considered viable and the legal aspects have thus not been evaluated.

Scenario 4: On-site use of the associated gas for liquefied natural gas production

This alternative has not been considered viable and the legal aspects have thus not been evaluated.

Scenario 5: Injection of the associated gas into an oil or gas reservoir

This alternative has not been considered viable and the legal aspects have thus not been evaluated.

Scenario 6: Recovery, transportation, processing and distribution of the associated gas and products thereof to end-users without being registered as a (JI) CDM project

This alternative has been considered viable from a technical standpoint, and is presented in detail in this PDD. As part of getting State approvals for the proposed JI project, TNK-BP has submitted a document pack to the Russian state expertise in accordance to the Russian guidelines for this type of procedure.

The legal department in TNK-BP does not foresee any issues related to obtaining the necessary State approvals, and the proposed JI project activity is evaluated to be in compliance with all applicable legal and regulatory requirements in the Russian Federation.

Scenario 7: Recovery, transportation and utilization of the associated gas as feedstock for manufacturing of a useful product

This alternative has not been considered viable and the legal aspects have thus not been evaluated.

Step 3: Evaluate the economic attractiveness of alternatives

The economic attractiveness of alternatives is analyzed in detail in Section B.2. As presented there, the continuation of current practice, i.e. flaring of APG from the last stages of oil separation, is found to be the most economically attractive alternative by TNK-BP.

Summary of identification of the baseline scenario:
From the seven alternative scenarios discussed above, the one that represents the most attractive economic course of action is technically feasible and in compliance with the relevant legislation will be the baseline scenario. As is further demonstrated in detail in Section B.2, the baseline scenario for the SNG gas gathering project is to continue current practice, i.e. flaring of LP APG from last stages of oil separation.

Project Area:
The project activity is located within the Samotlor oilfield. The Samotlor oilfield is the largest oilfield in TNK-BP's portfolio and is situated in the Nizhnevartovsk region of the Khanti Mansi autonomous Okrug of the Tyumen oblast, 750 km to the north east of the town Tyumen and 15 km from the town Nizhnevartovsk. The field was discovered in the 1960s, and the first producing well was in operation in 1969. The field reached peak production in 1980, and is now at a steady production level of about 400 000 bbl/d and is undergoing development as additional wells are being added over time.

The JI project infrastructure will be built within the SNG concession area, and all the 5 VCSs will be located within the premise of the 5 different oil treatment sites (BPS-Mykhpay, BPS-28, IGF-5, BPS-39 and BPS-26). The existing LP natural gas pipelines used to export the recovered APG to market are not considered part of this project activity.

Definition of Project Activity:
The project activity consists of:

- Design and construction of five VCSs at oil treatment sites IGF-5, BPS-Mykhpay, BPS-26, BPS-28, and BPS-39;
- Recovery of gas from last stages of oil treatment;
- Sales of APG and drop-out precipitate through the existing LP gas pipeline system.

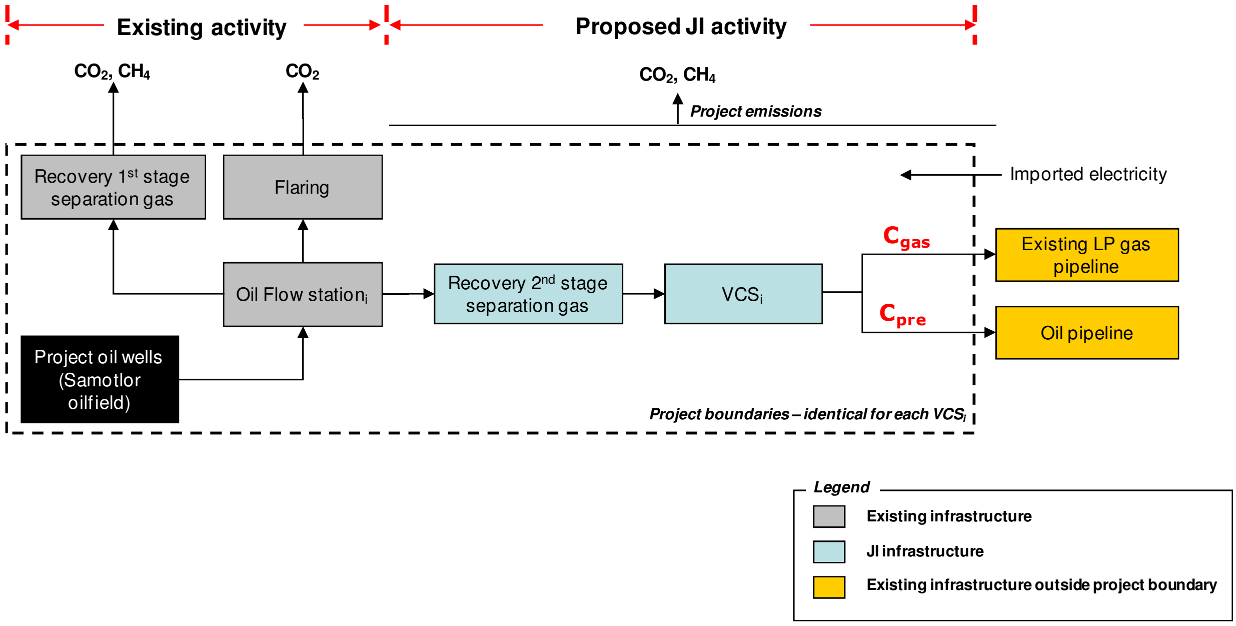

Figure 3: Schematic of the project boundaries around each of the 5 VCSs

Projection and adjustment of baseline and project emissions:
Baseline emissions are based on the quantity and composition of gas recovered as measured at each of the in-take points of the gas at the VCSs ("Recovery 2nd stage" in Figure 3). This gas is precisely the gas that would be flared absent this project. The quantity of recovered gas is primarily linked to the oil production. The associated gas production forecast in this PDD is based on TNK-BP's reservoir engineering studies and is directly related to the oil production vis-à-vis a gas-to-oil ratio of the oil produced.

The production of 2nd stage separation gas at each of the five VCSs is estimated to remain stable along with the oil production. The production of 2nd stage separation gas is estimated to be 90 MMCM in 2009, and production is anticipated to be stable for the next 20 years. A split of the production is summarized in the table below.

VCS name:	Daily rate (MCM/d)	Yearly rate (MMCM/yr)
VCS-28	35	12.6
VCS-39	70	25.2
VCS-Mykhpay	50	18.0
VCS-26	70	25.2
VCS-5	25	9.0
Total	250	**90.0**

While forecasts are used in this PDD, the quantity and composition of the recovered gas are monitored ex-post and baseline and project emissions are actual reductions as described in the monitoring plan (see Section D). The project emissions are those that occur in the infrastructure built for this project by the project developer and under his control.

Baseline Emissions:

The baseline emissions are those that would occur from the flaring of the APG absent this project activity.

The Samotlor oilfield utilizes modern flares at the flow stations where flaring of APG currently occurs. Flaring is often conducted under sub-optimal combustion conditions and part of the gas is not combusted, but released as methane and other volatile gases. However, measurement of the quantity of methane released from flaring is difficult and in this instance not considered significant enough to justify inclusion. Hence, for the purpose of determining baseline emissions, it is assumed that all carbon in the gas is converted into carbon dioxide. This is a conservative estimate.

As all flaring is done at the oil flow stations, the reduction in gas flaring is quite straightforward. The mass of carbon in the APG and drop-out precipitate exiting the VCSs is equivalent to the carbon that would have been released as CO_2 through flaring of APG absent this project activity.

The baseline emissions are calculated based on equation 1 in AM0009:

(1) $$BE_y = \frac{44}{12} \cdot \frac{1}{1000} \cdot \sum_i (V_{Cgas,i,y} \cdot w_{carbon,Cgas,i,y} + V_{Cpre,i,y} \cdot w_{carbon,Cpre,i,y})$$

Where:

BE_y	Baseline emissions during the period y, in tCO_2
$V_{Cgas,i,y}$	Volume of the gas entering the gas pipeline from VCS *i* measured at point C_{gas} in Figure 4 (located at the end of Section B.1) during the period y, in m^3
$V_{Cpre,i,y}$	Volume of precipitate entering the oil pipeline measured from VCS *i* at point C_{pre} in Figure 4 during the period y, in m^3
$w_{carbon,Cgas,i,y}$	Average carbon content of gas at point C in Figure 4, in kgC/m^3
$w_{carbon,Cpre,i,y}$	Average carbon content of precipitation at point C in Figure 4, in kgC/m3

Sources of project emissions:
The following sources of project emissions are accounted for in AM0009:

- CO_2 emissions due to fuel combustion for recovery, transport and processing of the gas (on-site energy use);
- CO_2 emission due to consumption of other fuels in place of the recovered gas (substitution);
- CH_4 and CO_2 emissions from leaks, venting and flaring during the recovery transport and processing of recovered gas.

According to AM0009, project emissions are calculated as follows:

(2) $$PE_y = PE_{CH4,gas,y} + PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y}$$

Where:

PE_y	Project emissions in year y, in tCO_{2e}

$PE_{CH4,gas,y}$ CH_4 emissions due to venting, leaks or flaring of the recovered gas during the transportation and processing of the associated gas during the period y, in tCO_{2e}

$PE_{CO2,fossilfuels,y}$ CO_2 emissions due to consumption of fossil fuels, including the associated gas if applicable, for the collection, transportation and processing of the associated gas during the period y, in tCO_{2e}

$PE_{CO2,elec,y}$ CO_2 emissions due to the use of electricity for the collection, transportation and processing of the associated gas during the period y, in tCO_{2e}

Of the potential sources of project emissions, only CO_2 emissions due to the use of electricity for the collection, transportation and processing of the associated gas is relevant to this project activity as will be explained below. This emission source is under control of the project participants and is thus contained within the project boundary. It is important to realize that gas processing is not part of this project activity.

CH_4 project emissions from venting, leak or flaring of the associated gas
As stated in the methodology, CH_4 from fugitive emissions during collection and transportation of the recovered gas are not calculated from single emission sources, but a carbon mass balance is conducted between points A, B, and X in Figure 1 in AM0009. The points A, B, and X delineate the gas processing plant described in Figure 1 of the methodology. As no gas processing exists in the proposed JI project activity; equations 3, 4, 5 and 6 in AM0009 are not applicable. All infrastructure built for the project activity will use modern equipment and conform to international best practice. Due to the short length of project pipelines, automatic cut-off valves and the fact that the project pipelines are completely within SNG's concession area thus assuring continuous surveillance, the likelihood of accidental leaks are anticipated to be negligible. As a result, emissions from venting, leak or flaring during operations are expected to be negligible.

Project emissions from the consumption of fossil fuels
No fossil fuels will be consumed on-site as a result of the project activity. All installed equipment will be supplied with electricity from the regional grid.

Project emissions from consumption of electricity
Electricity imported from the regional grid supplies the equipment installed for the project activity (i.e. the VCSs). The electricity is taken form the Khanty-Manskiysk regional grid, and the corresponding emissions are taken into account as project emissions. In order to calculate this source of project emissions, the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" is applied as specified in AM0009. Application of this Tool requires determination of the relevant grid emission factor and the average distribution losses in the grid. The grid emission factor for the electricity system supplying the proposed JI projects with electricity has been determined according to the "Tool to calculate the emission factor for an electricity system (version 01.1)" (see Annex 2 and Attachment 2). The average transmission and distribution loss in the grid has been determined in Attachment 2 based on international statistics from the IEA.

Following the discussion of sources of project emissions presented above, the formula used to estimate project emissions is:

(3) $$PE_y = PE_{CH4,gas,y} + PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y}$$

Where:

PE_y	Project emissions in period y, in tCO_{2e}
$PE_{CH4,gas,y}$	CH_4 emissions due to venting, leaks or flaring of the recovered gas during the transportation and processing of the associated gas during the period y, in tCO_{2e}. Based on the discussion above, the value of this parameter is zero throughout the crediting period and data to quantify the parameter is thus not monitored.
$PE_{CO2,fossilfuels,y}$	CO_2 emissions due to consumption of fossil fuels, including the associated gas if applicable, for the collection, transportation and processing of the associated gas during the period y, in tCO_{2e}. Based on the discussion above, the value of this parameter is zero throughout the crediting period and data to quantify the parameter is thus not monitored.
$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for the collection, transportation and processing of the associated gas during the period y, in tCO_{2e}

Leakage:
As noted in AM0009, leakage can typically occur due to the following situations:

- Emissions sources related to the recovery, transportation and processing of the gas, where the recovery, transportation and/or processing of the gas is not under control of project participants;
- Changes in CO_2 emissions due to the substitution of fuels or additional fuel consumption at end-users, where these effects occur (effects listed in AM0009 version 03.2 under "Leakage").

Concerning the first category, all the sources of project emissions related to recovery and transportation of gas into the existing LP gas export network in Samotlor is under the control of the project developer. The only identified source of emissions that is located outside the project boundary is energy consumption for processing of the gas into marketable products. Utilizing the principle of conservatism, the emissions from consumption of electricity for downstream processing of the recovered gas is included as a source of potential leakage emissions. Furthermore, these emissions are quantified by assuming that all the recovered gas is processed in the regional gas processing plant (physically linked to the Samotlor oil field) with the highest historical electricity consumption per m^3 of gas processed. This is a conservative approach. The leakage emissions from consumption of electricity for processing of the gas are calculated in accordance with "Tool to calculate baseline, project and/or leakage emissions from electricity consumption (version 01)". As there is no direct monitoring of electricity consumption in the regional GPP with the highest historical electricity consumption outside the project boundary, the historical electricity consumption intensity (i.e. $MWh/000m^3$ of gas processed) of this GPP is multiplied with the actual amount of gas recovered by the project activity to determine the electricity consumption for downstream processing of recovered gas (see Equation 5 below for details).

The existing LP gas export network that will be used to transport the recovered gas to the regional GPPs is currently utilized to transport all the APG from Samotlor oilfield for downstream processing. The transport distances from the VCSs to the GPPs are such (<50km) that there is no need for re-compression of the gas along the various pipeline routes. In line with the guidance provided by the 1995 "Protocol for Equipment Leak Emission Estimates", published by the US EPA[7] the fugitive emissions from pipeline transportation are assumed to be negligible and are thus excluded from the calculation of leakage emissions.

Concerning the second category, the recovered gas and products thereof are not expected to substitute fuels with a lower carbon content nor result in additional fuel consumption at end-users (see discussion

[7] http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf

around applicability conditions required in AM0009 version 03.2 presented in Section B.1 for more details).

Based on the discussions above, leakage emissions are calculated as follows:

(4) $$LE_y = EC_{GPP,y} \cdot EF_{grid,y} \cdot (1 + TDL_y)$$

With:

(5) $$EC_{GPP,y} = \sum_i V_{Cgas,i,y} \cdot \frac{1}{1000} \cdot EI_{GPP,y}$$

Where:

LE_y	Leakage emissions during the period y, in tCO_{2e}
$V_{Cgas,i,y}$	Volume of the gas entering the gas pipeline from VCS *i* measured at point C_{gas} in Figure 4 during the period y, in m^3
$EI_{GPP,y}$	Electricity consumption per m^3 gas processed in the most energy intensive GPP in the region, in kWh/000m^3
$EF_{grid,y}$	Emission factor for the grid in the period y (tCO_2/MWh)
TDL_y	Average technical transmission and distribution losses in the grid in the period y for the voltage level at which electricity is obtained from the grid at the project site

Emission Reductions:
Based on the forgoing discussion, the emission reductions for the project are straightforward and equal to the baseline emissions minus all project related emissions and leakage emissions – converted to tons of CO_2 equivalent. Equation number (7) in AM0009 is used to determine the emission reductions.

Monitoring:
Following the monitoring methodology of AM0009 version 03.2 and taking into account the specific situation of the proposed JI project activity, the following data are needed to correctly determine the emission reductions:

- Volume of recovered gas entering the existing LP gas pipelines from each of the five VCSs;
- Quantity of precipitate entering the oil pipelines from each of the five VCSs;
- Composition of the recovered gas entering the LP gas pipelines from each of the five VCSs;
- Composition of precipitate entering the oil pipelines from each of the five VCSs;
- Electricity consumption in each of the five VCSs;
- The grid emission factor for the Khanty-Manskiysk regional grid;
- The average distribution losses for the Khanty-Manskiysk regional grid;

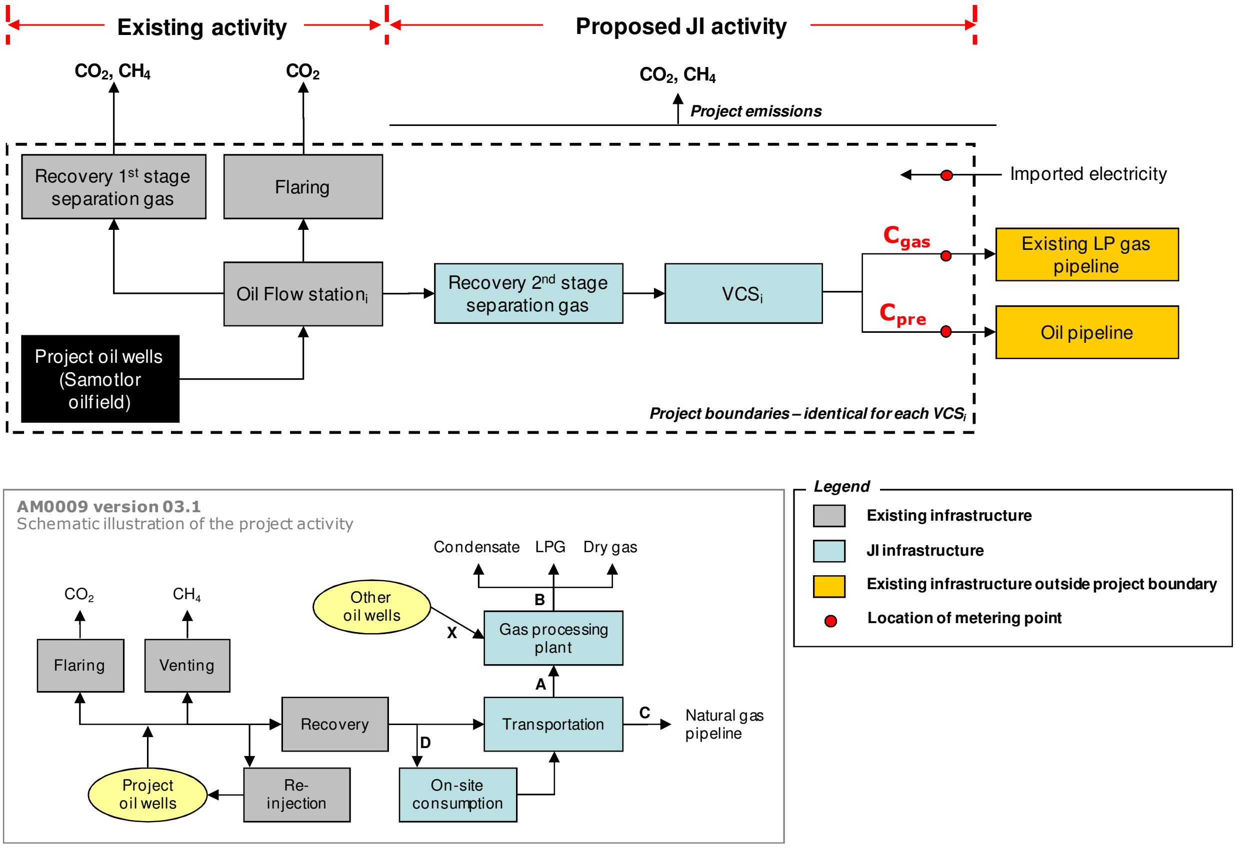

Figure 4: Schematic of the location of monitoring points

These data needs are met by this project activity. Indeed, care has been taken to assure that the project design and schematic for this project activity overlay that in AM0009 (see Figure 4). Points A, B and X are not relevant to this project activity as explained above.

B.2. Description of how the anthropogenic emissions of greenhouse gases by sources are reduced below those that would have occurred in the absence of the JI project:

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To demonstrate that the anthropogenic emissions of greenhouse gases are reduced below those that would have occurred in the absence of the JI project, the stepwise procedure described in AM0009 version 03.2 is followed. These steps are:

Step 1. Identify plausible alternative scenarios
Step 2. Evaluate legal aspects
Step 3. Evaluate the economic attractiveness of alternatives

In addition to the above steps, AM0009 version 03.2 contains a reference to the "Combined tool to identify the baseline scenario and demonstrate additionality" (version 02.2). To strengthen the assessment and demonstration of additionality, the common practice analysis referred to in this Tool has also been carried out:

Step 4. Common practice analysis

The first two steps were carried out in Section B.1. Out of the seven alternative scenarios analyzed in Section B.1, only two plausible alternative scenarios that are in compliance with all applicable legal and regulatory requirements were identified.

Step 3: Evaluate the economic attractiveness of alternatives

Apart from continuation of current practice, the proposed JI project activity was found to provide the most attractive alternative to increase utilization of APG at SNG. The economic attractiveness of these two alternatives has been compared to demonstrate additionality:

2. *Flaring of LP APG from the last stages of oil separation at the 5 production sites*
6. *The proposed JI project activity*

The figures presented below represents the data available at the time of making the investment decision within TNK-BP, i.e. March 2008.

The evaluation of the two plausible alternatives has been done based on generally acceptable methods and principles used within the oil and gas industry as well as the fiscal regime under which the project developer operates in Russia. The project financial returns are calculated on a project, stand alone basis, as is normal for such evaluation.

The continuation of current practice is used as a baseline when determining the economic attractiveness of the two alternatives. The economics is assessed based on the project Internal Rate of Return (IRR) post-tax of the proposed JI project activity. The benchmark applied by TNK-BP to evaluate investment proposals related to upstream oil and gas investments post-tax has been disclosed to the DOE for validation. In addition to the project IRR post-tax, the Net Present Value (NPV) post-tax is also presented utilizing TNK-BP's benchmark return (i.e. standard discount rate) used for investment analysis.

2. *Flaring of the LP APG from the last stages of oil separation at the five production sites (Scenario 2 in Section B.1)*

Flaring of low pressure APG from the last stages of oil separation is the current practice at each of the five production sites covered in this PDD, and the economics of this alternative will not be evaluated specifically as the continuation of this flaring represents the business as usual case and therefore requires no new investment. Financial savings related to reduction in fines for stationary combustion are included in the economic analysis of the alternative to continuation of current practice.

6. *The proposed JI project activity (Scenario 6 in Section B.1)*

To take advantage of the increasing value of APG and related products and comply with the APG utilization requirements in the licensing agreements, several regional project teams were established to explore, assess and implement the optimal options for APG usage within TNK-BP. Considering the importance of the issue, the company launched an APG resource audit program in August 2005 to define options for gas use and compositions at flares and develop recommendations to optimize the APG collection and transportation system operations.

As a result of this work, TNK-BP obtained APG data for Samotlor with breakdown by separation stage as well as hydraulic calculations for the gas-gathering and transportation networks in the area; so that the performance of each oil production unit could be evaluated. This allowed TNK-BP to identify the opportunity to install five VCSs to recover an additional 90 MMCM of LP APG from the last stages of oil separation at five production sites in the south-western part of the Samotlor oilfield. This option was developed into the proposed JI project activity.

The economics of the proposed JI project activity is determined from the cost of installing and operating the necessary equipment to recover, treat, compress and transport the APG to the existing pipeline system, plus the net-back value of the APG and precipitate recovered, specifically:

- Capital and operating expenditures for the five VCSs;
- The value of the APG delivered to one of the regional GPPs for processing into marketable products;
- The value of precipitate that is separated out in the VCSs and sold via the existing oil pipeline;
- The reduction in environmental fines for stationary combustion that results from the reduced flaring of APG. (The reduction in environmental fines is included as a benefit when evaluating the proposed JI project rather than a cost when evaluating the continuation of current practice.)

As will be shown below, the financial returns earned by the project developer for implementing the proposed JI project are marginal.

The following parameters are used in evaluating the financial performance of the project:

- The projected quantity of gas recovered, excluding any gas flared for operational reasons, vented or consumed on-site;
- The composition of the gas;
- Capital expenditures for the gas recovery facilities, i.e. VCSs, etc.;
- Operational costs;
- Net-back prices for stable hydrocarbon condensate (precipitate) and recovered APG;
- Tax regime in the relevant region of the Russian Federation;

Concerning the analysis, all costs and prices are treated in terms of 2008 USD and the analysis is done in this currency independent of any changes in real inflation or exchange rates. The major variables expressed in terms of 2008 USD are:

Operating costs (OPEX):

Operating costs of the five VCSs are estimated based on forecasts by TNK-BP, i.e. 2.6 million USD per annum as of 2011. The main components of the operating costs are the cost of electricity from the regional grid and labor costs for staff to operate the VCSs.

Capital expenditures (CAPEX):

Capital costs of 22.43 million USD which covers the design, construction and installation cost of the 5 VCSs. A breakdown of CAPEX has been provided to the DOE.

Reduction in fines for stationary combustion:

The implementation of the JI project activity will reduce the payment of fines for stationary combustion of gas within the oil field. Therefore the financial analysis of the project specifically includes this benefit.

Net-back prices used in the analysis:

The prices required to analyze the economic performance of this project are:

- Net-back price of stable hydrocarbon condensate (precipitate)
- TNK-BP net-back price of APG

Net-back prices are calculated from regional market price assumptions and applicable transport tariffs. The net-back price of stable hydrocarbon condensate (precipitate) utilized for analysis has been provided to the DOE. This price forecast was utilized by TNK-BP at the time of making the final investment decision and is derived from a scenario taking into consideration the structure of the regional market.

Based on the gas processing capacity in the region, current commercial structures and agreements, the availability of gas supplies in the region and the expected development of market prices for processed products, the maximum net-back value of APG that can be applied to evaluate the IRR of the proposed JI project activity has been determined. The highly optimistic net-back value of APG applied for analysis increases from 42.6 USD/000 m^3 in 2009 to a level of 65.2 USD/000 m^3 in 2012 where it then stabilizes. The applied net-back price is considerable higher than the current regulated price of APG in Russia, and takes into account that TNK-BP has financial interests in the downstream processing of APG through its joint venture with Sibur; LLC Yugragazpererabotka (YGP), owned 49% by TNK-BP and 51% by Sibur.

Evaluation of project economics:

Due to the integrated and regional nature of the gas value chain, TNK-BP made the investment decision of the proposed JI project based on a NPV calculation of the cost of installation and operation of the gas gathering network adjusted for a qualitative evaluation of indirect benefits. The evaluation of potential benefits included the illustration of a cost efficiency indicator as well as *"the potential for qualifying the project as a Joint Implementation (JI) project under the Kyoto Protocol"*[8]

Assuming a financial lifetime of the project of 20 years, the key financial indicators for the SNG Gas Gathering Project illustrated on a stand-alone basis are:

Proposed JI project activity:	**Optimistic net-back values applied: NPV_{2008} (USD):**
Capital expenditures:	-19,926,000
Operating expenses:	-16,562,000
Revenues (AG, precipitate):	43,385,000
Taxes (property tax, income tax, VAT payable):	-10,619,000
Financial savings from environmental fines:	0,601,000
Total NPV:	**-3,122,000**
Project IRR post-tax:	**9.7 %**

As can be seen from the table above, the financial returns earned by the project developer for implementing the proposed JI project are substantially below what is normally required for investments by TNK-BP.

[8] The full wording of the relevant section of the Financial Memorandum for "Gas gathering, PU SNG" has been made available to the validator.

For robustness a sensitivity analysis was undertaken of +/- 10% of the key variables. The sensitivity analysis was conducted by varying the production profile of APG, the price assumptions of processed products, operational and capital expenditures by +/- 10%. The implications of these variations in parameters values with respect to the project IRR post-tax can be found in the table below:

Parameter name:	IRR (-10%[9])	Base case parameter value	IRR (+10%[10])
APG production forecast	7.0 %	1.687 MMCM over the lifetime	12.1 %
CAPEX	11.1 %	22.427 million USD	8.4 %
OPEX	10.9 %	48.334 million USD to 2027	8.4 %
Net-back value APG	7.9 %	65.2 USD/000 m^3 from 2012	11.3 %
Net-back value precipitate	9.2 %	Value provided to the DOE	10.2 %

Variations in the APG production forecast have the largest impact on project returns. As the Samotlor oilfield has been producing since 1969, the production forecast is based on detailed geological and geophysical studies and has limited uncertainty (+/- 5%). The project economic returns are also sensitive to changes in the net-back value of APG. Changes in the net-back value of APG are largely determined by the structure of the regional dry gas market, with transmission capacity controlled by Gazprom. The net-back value profile utilized is very optimistic and is based on predicted increases in end-user market values. Uncertainty is primarily related to delays in price liberalization (i.e. downward uncertainty). Other parameters are less uncertain (CAPEX) or have lower impact on the project economic returns (OPEX and net-back value precipitate). The sensitivity analysis shows that the conclusion regarding the financial attractiveness is robust to reasonable variations in critical assumptions.

The economics of the proposed JI project and the assumptions behind the calculations are further explained in Attachment 1.

While the technologies to be utilized in the proposed project are well known, there are risks associated with the physical implementation of the project. TNK-BP has carried out a benchmark analysis of two similar projects to reveal positive and negative lessons learned, and found that lack of technical supervision, improper staffing, erroneous and incomplete project documentation and poor quality of subcontractor work poses the most important risks.

Impact of JI Registration:
If the project activity is registered as JI, the resulting income from sale of ERUs makes a major impact on the project economics. This point has been important and is a significant reason the project implementation/execution was approved by TNK-BP management.

Due to the value of APG being relatively limited in Russia, the income from sale of ERUs have a magnified impact in that they are sold at relatively high prices in the international market. Given that the capital cost of the project activity is limited, the impact of the ERUs on the IRR is high, albeit the absolute value of the NPV is not large given the size of the overall project. The figures are shown below:

Proposed JI project activity	NPV_{2008} (USD):
NPV cash flow without ERU revenues:	-3,122,000
ERU revenues (20 USD/ERU to 2012, 10.0 USD/ERU thereafter):	16,160,000
Total NPV including income from sale of ERUs:	**13,038,000**
IRR:	**23.4%**

[9] Refers to a % change in parameter value(s) applied for sensitivity analysis.

Given these prospective economic returns, it is clearly in TNK-BP's best interest to incur the costs of implementation of the project activity and its registration as JI.

Baseline and additionality summary:

According to AM0009, *"the alternative scenario that is economically the most attractive course of action is considered as the baseline scenario"*. In this context, the continuation of current practice, i.e. flaring of APG from the last stages of oil separation, is found to be the most economically attractive alternative scenario by TNK-BP.

Scenario:	**Legal issues:**	**Economic attractiveness:**	**Conclusion:**
Release of the associated gas into the atmosphere at the oil production site (venting)	Not evaluated as the alternative is unfeasible	Not evaluated as the alternative is unfeasible	Not a feasible alternative
Flaring of the gas at the oil production site	Not prohibited by law	Attractive	Most attractive course of action
On-site use of the associated gas for power production	Not evaluated as the alternative is unfeasible	Highly unattractive	Not a feasible alternative
On-site use of the associated gas for LNG production	Not evaluated as the alternative is unfeasible	Highly unattractive	Not a feasible alternative
Injection of the associated gas into the producing oil reservoir	Not evaluated as the alternative is unfeasible	Highly unattractive	Not a feasible alternative
Recovery and transportation of the associated gas via pipelines to an existing GPP	Not prohibited by law	Unattractive	Not a feasible alternative
Recovery and utilization of the associated gas as feedstock for methanol production	Not evaluated as the alternative is unfeasible	Highly unattractive	Not a feasible alternative

The proposed JI project activity is evaluated as the most attractive alternative to the continuation of current practice (baseline scenario). Without revenues from sale of ERUs the project economics of this alternative are however unattractive with a project IRR post-tax considerably lower than the hurdle rate applied by TNK-BP. The potential to register the project as a JI project was considered important at the time of making the investment decision.

Summary of the assessment and demonstration of additionality:

Given that the proposed JI project would not have been implemented without the JI component and taking into account that the project allows for a significant reduction in GHG emissions below the baseline level, the project activity is considered to be additional.

B.3. Description of how the definition of the project boundary is applied to the project:

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The project boundary encompasses all new gas related infrastructure under the control of the project developer that is constructed and relevant for this project activity (see Figure 3). Therefore it includes the five VCSs that recover the gas from the last stage of separation at the five oil treatment facilities.

The table below presents the gases and their sources which are included in the project boundary. Flaring of gas constitutes the main source of emissions in the baseline scenario. The emissions of the project activity come from the energy used for recovery, transportation and processing of the APG.

	Source	Gas	Included?	Justification / Explanation
Baseline	Flaring	CO_2	Yes	Main source of emissions in baseline
		CH_4	No	Flaring does not achieve complete oxidation, so that some CH_4 is released in the atmosphere. As in AM0009, the flare efficiency is assumed to be 100%, and no CH_4 emitted. This is a conservative assumption.
		N_2O	No	Assumed negligible
Project Activity	Energy use for recovery, transportation and processing of the recovered gas	CO_2	Yes	Emissions from natural gas (or any other fossil fuel) used in these facilities
		CH_4	No	Assumed negligible
		N_2O	No	Assumed negligible
	Energy emissions during collection and transportation of the recovered gas	CO_2	No	Not relevant to the project activity
		CH_4	No	Not relevant to the project activity
		N_2O	No	Not relevant to the project activity
	Fugitive Emissions from accidents	CO_2	No	Assumed negligible
		CH_4	No	Assumed negligible due to very short pipelines, automatic shut-off valves and continuous surveillance
		N_2O	No	Assumed negligible

B.4. Further baseline information, including the date of baseline setting and the name(s) of the person(s)/entity(ies) setting the baseline:

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Carbon Limits is the entity determining the baseline and participating in the project as JI developer. The baseline calculations are based on the most recent data available. The baseline development was finalized November 19, 2008. The person in charge of its development is:

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Biskop Gunnerius' gt. 14A
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NO-0051 Oslo
Norway
Phone: +47 92 80 86 40 / +47 45 40 50 00
Email: anders.pederstad@carbonlimits.no

Please see Annex 2 for further details on baseline development.

SECTION C. Duration of the project / crediting period

C.1. Starting date of the project:

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The definition of the start date of the project activity is according to the definition determined in EB 33 *"the dates at which the implementation or construction or real action of the project activity begins"*.

A financial memorandum for the SNG gas gathering project was prepared in Q1 2008, and the formal decision to move the project to the EXECUTE stage was made 06 March 2008.

The start date of the proposed JI project is according to EB guidance set to 06 March 2008, and the VCSs are planned commissioned in March 2009.

C.2. Expected operational lifetime of the project:

>>
The equipment installed is expected to have a physical lifetime of more than 20 years.

C.3. Length of the crediting period:

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The starting date of the crediting period for the JI project is set to 01 April 2009. The end of the crediting period is 31 March 2019. Thus, the length of the crediting period is 10 years, i.e. the entire period during which emission reductions are generated is 120 months.

Emission Reduction Units generated for the period after the first commitment period of the Kyoto Protocol (2008 to 2012) is pending on any relevant agreement under the UNFCCC and approval by the Russian Federation.

SECTION D. Monitoring plan

D.1. Description of monitoring plan chosen:

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The monitoring methodology for this project activity is that contained in the approved methodology used for this project activity, "Recovery and utilization of gas from oil wells that would otherwise be flared", AM0009 version 03.2.

Following the monitoring methodology of AM0009 version 03.2 and taking into account the specific situation of the proposed JI project activity, the following data are needed to correctly determine the emission reductions:

- Volume of recovered gas entering the existing LP gas pipelines from each of the five VCSs;
- Quantity of precipitate entering the oil pipelines from each of the five VCSs;
- Composition of the recovered gas entering the existing LP gas pipelines from each of the five VCSs;
- Composition of precipitate entering the existing oil pipelines from each of the five VCSs;
- Electricity consumption in each of the five VCSs;
- The grid emission factor for the Khanty-Manskiysk regional grid;
- The average distribution losses for the Khanty-Manskiysk regional grid;

The physical layout of the monitoring points for each of the five VCSs is illustrated in Figure 4 in Section B.1.

D.1.1. Option 1 – Monitoring of the emissions in the project scenario and the baseline scenario:

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D.1.1.1. Data to be collected in order to monitor emissions from the project, and how these data will be archived:

ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1.	$EC_{PJ,i,y}$	*Electricity consumed by VCS i, electricity meter*	*MWh*	*m*	*Continuous*	*All*	*Electronic and paper*	*One measurement for each VCS i.*
2.	$EF_{grid,y}$	*Emission factor for the*	*tCO_2/MWh*	*c/e*	*Annually*	*None*	*Electronic*	*Estimated at 0.609 tCO_2/MWh.*

		regional grid					*and paper*	*See Annex 2 for calculations*
3.	TDL_y	*Transmission and distribution losses in the grid*	*%*	*c*	*Annually*	*None*	*Electronic and paper*	*Estimated at 12.0 %. See Attachment 2 for rationale.*

D.1.1.2. Description of formulae used to estimate project emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

>>
Following the discussion of sources of project emissions presented in Section B.1, the formula used to estimate project emissions is:

(3) $$PE_y = PE_{CH4,gas,y} + PE_{CO2,fossilfuels,y} + PE_{CO2,elec,y}$$

Where:

PE_y	Project emissions in period y, in tCO_{2e}
$PE_{CH4,gas,y}$	This parameter has due to project characteristics explained in Section B.1 a value of zero (0) throughout the crediting period
$PE_{CO2,fossilfuels,y}$	This parameter has due to project characteristics explained in Section B.1 a value of zero (0) throughout the crediting period
$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for the recovery, compression and transportation of APG during the period y, in tCO_{2e}

CO_2 emission due to consumption of electricity:
Electricity imported from the regional grid will be consumed to operate the equipment installed as part of the project activity (i.e. the VCSs). The electricity is taken from the Khanty-Manskiysk regional grid, and the corresponding emissions are taken into account as project emissions. In order to calculate this source of project emissions, the latest approved version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" is applied as specified in AM0009. This Tool further refers to the approved "Tool to calculate the emission factor for an electricity system (version 01.1)" in order to determine the emission factor of the grid. The calculation of the Tyumen grid emission factor can be found in Annex 2 in this PDD.

The CO_2 emissions due to consumption of electricity are calculated as follows:

(6) $$PE_{CO2,elec,y} = \sum_i EC_{PJ,i,y} \cdot EF_{grid,y} \cdot (1 + TDL_y)$$

Where:

$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for the recovery, compression and transportation of APG during the period y, in tCO2e
$EC_{PJ,i,y}$	Quantity of electricity consumed at VCS *i* during the period y (MWh)
$EF_{grid,y}$	Emission factor for the grid in the period y (tCO_2/MWh)
TDL_y	Average technical transmission and distribution losses in the grid in the period y for the voltage level at which electricity is obtained from the grid at the project site

Grid emission factor:
As all the electricity consumed as a result of the project activity is purchased from the grid, Option A1 in the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption" is applied to determine the emission factor of the grid; i.e. calculation of the combined margin emission factor of the applicable electricity system. The operating margin and the build margin for the electrical grid will be calculated ex-post and updated annually. The calculation of the grid emission factor is presented in Annex 2. As shown in Annex 2 (and further explained in Attachment 2), the grid emission factor for the regional grid is estimated to be 0.609 tCO_{2e}/MWh, and this value is applied throughout the crediting period for the purpose of estimating the emission reductions.

Average technical transmission and distribution losses in the grid
The average technical transmission and distribution losses are estimated to be 12.0% based on statistics from IEA for the Russian Federation (see Attachment 2). This value is monitored for each period y in line with guidance provided in the latest version of the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption".

D.1.1.3. Relevant data necessary for determining the baseline of anthropogenic emissions of greenhouse gases by sources within the project boundary, and how such data will be collected and archived:

ID number	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/paper)	Comment
1.	$V_{Cgas,VCS-28,y}$	*Flow meter*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-28*
2.	$V_{Cgas,VCS-39,y}$	*Flow meter*	*m3*	*m*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-39*

3.	$V_{Cgas,VCS-Mykhpay,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of gas from VCS-Mykhpay
4.	$V_{Cgas,VCS-26,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of gas from VCS-26
5.	$V_{Cgas,VCS-5,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of gas from VCS-5
6.	$V_{Cpre,VCS-28,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of precipitate from VCS-28
7.	$V_{Cpre,VCS-39,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of precipitate from VCS-39
8.	$V_{Cpre,VCS-Mykhpay,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of precipitate from VCS-Mykhpay
9.	$V_{Cpre,VCS-26,y}$	Flow meter	m3	+m	Continuous	All	Electronic and paper	Total volume of precipitate from VCS-26
10.	$V_{Cpre,VCS-5,y}$	Flow meter	m3	m	Continuous	All	Electronic and paper	Total volume of precipitate from VCS-5
11.	$w_{carbon,Cgas,VCS-28,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of gas at outlet of VCS-28
12.	$w_{carbon,Cgas,VCS-39,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of gas at outlet of VCS-39
13.	$w_{carbon,Cgas,VCS-Mykhpay,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of gas at outlet of VCS-Mykhpay
14.	$w_{carbon,Cgas,VCS-26,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of gas at outlet of VCS-26
15.	$w_{carbon,Cgas,VCS-5,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of gas at outlet of VCS-5
16.	$w_{carbon,Cpre,VCS-28,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of precipitate at outlet of VCS-28
17.	$w_{carbon,Cpre,VCS-39,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of precipitate at outlet of VCS-39
18.	$w_{carbon,Cpre,VCS-Mykhpay,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of precipitate at outlet of VCS-Mykhpay
19.	$w_{carbon,Cpre,VCS-26,y}$	Composition analysis at outlet of VCS	kgC/m3	m	Sampled weekly	Sampled	Electronic and paper	Composition of precipitate at outlet of VCS-26

20.	$w_{carbon,Cpre,VCS-5,y}$	*Composition analysis at outlet of VCS*	*kgC/m3*	*m*	*Sampled weekly*	*Sampled*	*Electronic and paper*	*Composition of precipitate at outlet of VCS-5*

D.1.1.4. Description of formulae used to estimate baseline emissions (for each gas, source etc.; emissions in units of CO_2 equivalent):

>>

The baseline emissions are calculated from Equation 1 presented in Section B.1:

(1) $$BE_y = \frac{44}{12} \cdot \frac{1}{1000} \cdot \sum_i (V_{Cgas,i,y} \cdot w_{carbon,Cgas,i,y} + V_{Cpre,i,y} \cdot w_{carbon,Cpre,i,y})$$

Where:

BE_y	Baseline emissions during the period y, in tCO_2
$V_{Cgas,i,y}$	Volume of the gas entering the gas pipeline from VCS *i* measured at point C_{gas} in Figure 4 during the period y, in m^3
$V_{Cpre,i,y}$	Volume of precipitate entering the oil pipeline measured from VCS *i* at point C_{pre} in Figure 4 during the period y, in m^3
$w_{carbon,Cgas,i,y}$	Average carbon content of gas from VCS *i* measured at point C_{gas} in Figure 4, in kgC/m^3
$w_{carbon,Cpre,i,y}$	Average carbon content of precipitate from VCS *i* measured at point C_{pre} in Figure 4, in kgC/m^3

D. 1.2. Option 2 – Direct monitoring of emission reductions from the project (values should be consistent with those in section E.):

D.1.2.1. Data to be collected in order to monitor emission reductions from the project, and how these data will be archived:

ID number *(Please use numbers to ease cross-referencing to D.2.)*	Data variable	Source of data	Data unit	Measured (m), calculated (c), estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment

>>

Not applicable.

D.1.2.2. Description of formulae used to calculate emission reductions from the project (for each gas, source etc.; emissions/emission reductions in units of CO_2 equivalent):

>>
Not applicable

D.1.3. Treatment of leakage in the monitoring plan:

>>

D.1.3.1. If applicable, please describe the data and information that will be collected in order to monitor leakage effects of the project:

ID number	Data variable	Source of data	Data unit	Measured (m), calculated ©, estimated (e)	Recording frequency	Proportion of data to be monitored	How will the data be archived? (electronic/ paper)	Comment
1.	$V_{Cgas,VCS-28,y}$	*Flow meter*	*m3*	*M*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-28*
2.	$V_{Cgas,VCS-39,y}$	*Flow meter*	*m3*	*M*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-39*
3.	$V_{Cgas,VCS-Mykhpay,y}$	*Flow meter*	*m3*	*M*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-Mykhpay*
4.	$V_{Cgas,VCS-26,y}$	*Flow meter*	*m3*	*M*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-26*
5.	$V_{Cgas,VCS-5,y}$	*Flow meter*	*m3*	*M*	*Continuous*	*All*	*Electronic and paper*	*Total volume of gas from VCS-5*
6.	$EI_{GPP,y}$	*Electricity consumption intensity of downstream GPP*	*kWh/000m^3*	*c/e*	*Determined ex-ante*	*None*	*Electronic and paper*	*Fixed at 274.1 kWh/000m^3. Electricity consumption per m^3 of gas processed in most energy intensive GPP in the region*
7.	$EF_{grid,y}$	*Emission factor for the regional grid*	*tCO_2/MWh*	*c/e*	*Annually*	*None*	*Electronic and paper*	*Estimated at 0.609 tCO_2/MWh. See Annex 2 for calculations*
8.	TDL_y	*Transmission and distribution losses*	*%*	*c*	*Annually*	*None*	*Electronic and paper*	*Estimated at 12.0 %. See Attachment 2 for rationale.*

		in the grid						

D.1.3.2. Description of formulae used to estimate leakage (for each gas, source etc.; emissions in units of CO_2 equivalent):

>>

Based on the discussion in Section B.1, one source of leakage emissions is included as a conservative approach; emissions from electricity consumption for downstream processing of recovered gas before marketing of gas and products thereof to end users.

Leakage emissions are calculated as follows:

(4) $$LE_y = EC_{GPP,y} \cdot EF_{grid,y} \cdot (1 + TDL_y) \cdot \frac{1}{1000}$$

Where:

LE_y	Leakage emissions during the period y, in tCO_{2e}
$EC_{GPP,y}$	Electricity consumption related to downstream processing of recovered gas during the period y (MWh)
$EF_{grid,y}$	Emission factor for the grid in the period y (tCO_2/MWh)
TDL_y	Average technical transmission and distribution losses in the grid in the period y for the voltage level at which electricity is obtained from the grid at the project site

The determination of the electricity consumption related to downstream processing of recovered gas is based on the assumption that all the recovered gas is processed in the regional gas processing plant (physically linked to the Samotlor oil field) with the highest historical electricity consumption per m^3 of gas processed. The energy consumption per m^3 of recovered gas processed (i.e. the intensity of consumption) is multiplied with the actual volume of gas recovered as a result of the project activity to determine the energy consumption related to processing of recovered gas:

(5) $$EC_{GPP,y} = \sum_i V_{Cgas,i,y} \cdot \frac{1}{1000} \cdot EI_{GPP,y}$$

Where:

$EC_{GPP,y}$	Electricity consumption related to downstream processing of recovered gas during the period y (MWh)
$V_{Cgas,i,y}$	Volume of the gas entering the gas pipeline from VCS *i* measured at point C_{gas} in Figure 4 during the period y, in m^3
$EI_{GPP,y}$	Electricity consumption per m^3 gas processed in the most energy intensive GPP in the region, in kWh/000m^3

D.1.4. Description of formulae used to estimate emission reductions for the project (for each gas, source etc.; emissions/emission reductions in units of CO_2 equivalent):

>>
Equation 7 in AM0009 is used to determine the emission reduction:

(8) $$ER_y = BE_y - PE_y - LE_y$$

Where:

ER_y	Emission reductions of the project activity during the period y, in tons of CO_{2e}
BE_y	Baseline emissions in year y, in tons of CO_2
PE_y	Project emissions in year y, in tons of CO_2
LE_y	Leakage emissions in year y, in tons of CO_2

D.1.5. Where applicable, in accordance with procedures as required by the host Party, information on the collection and archiving of information on the environmental impacts of the project:

>>
Not applicable.

D.2. Quality control (QC) and quality assurance (QA) procedures undertaken for data monitored:

Data *(Indicate table and ID number)*	Uncertainty level of data (high/medium/ low)	Explain QA/QC procedures planned for these data, or why such procedures are not necessary.
D.1.1.1 – 1	*Low (+/- 0.25 %)*	*This parameter will be continuously monitored and recorded as part of standard operations. Calibration and maintenance are executed according to national and manufacturer norms. Cross check electricity purchase receipts for SNG.*
D.1.1.1 – 2 *D.1.3.1 - 7*	*Medium*	*The grid emission factor of the regional grid has been estimated based on publicly available historical data for the last three years. Detailed data on fuel consumption and dispatch procedures are not publicly available. The value should be determined annually ex-post in line with the most recent version of the "Tool to calculate the emission factor for an electricity system" in a conservative manner.*
D.1.1.1 – 3 *D.1.3.1 - 8*	*Medium*	*The average transmission losses of Russian electricity transmission systems have been estimated based on international statistics from the IEA (2005) for the Russian Federation (see Attachment 2). The value should be determined annually, e.g. by the IEA international statistics for the Russian Federation for the relevant year. In absence of data from the relevant year, most recent figures should be used but not older than 5 years. .*
D.1.1.3 – 1 *D.1.3.1 - 1*	*Low (+/-1%)*	*This parameter is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80. As a quality control measure, the parameter value can only be set to the monitored value for the purpose of determining the emission reductions if it can be documented through signed statements from the operating companies that there have been no unpredicted emergency shut-downs of regional gas processing capacity or gas transportation capacity. If documentation can not be provided for a period, a value of zero for this parameter must be applied for this period when determining the emission reductions ex-post. If there are any unpredicted emergency events, the parameter value should be set to zero on a daily basis as long as there is a shut-down during the respective calendar day irrespective of the exact duration of the shut-down. This is a conservative approach.*
D.1.1.3 – 2 *D.1.3.1 - 2*	*Low (+/-1%)*	*This parameter is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80. As a quality control measure, the parameter value can only be set to the monitored value for the purpose of determining the emission reductions if it can be documented through signed statements from the operating companies that there have been no unpredicted emergency shut-downs of regional gas processing capacity or gas transportation capacity. If documentation can not be provided for a period, a value of zero for this parameter must be applied for this period when determining the emission reductions ex-post. If there are any unpredicted emergency events, the parameter value should be set to zero on a daily basis as long as there is a shut-down during the respective calendar day irrespective of the exact duration of the shut-down. This is a conservative approach.*

D.1.1.3 – 3 *D.1.3.1 - 3*	*Low (+/-1%)*	*This parameter is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80. As a quality control measure, the parameter value can only be set to the monitored value for the purpose of determining the emission reductions if it can be documented through signed statements from the operating companies that there have been no unpredicted emergency shut-downs of regional gas processing capacity or gas transportation capacity. If documentation can not be provided for a period, a value of zero for this parameter must be applied for this period when determining the emission reductions ex-post. If there are any unpredicted emergency events, the parameter value should be set to zero on a daily basis as long as there is a shut-down during the respective calendar day irrespective of the exact duration of the shut-down. This is a conservative approach.*
D.1.1.3 – 4 *D.1.3.1 - 4*	*Low (+/-1%)*	*This parameter is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80. As a quality control measure, the parameter value can only be set to the monitored value for the purpose of determining the emission reductions if it can be documented through signed statements from the operating companies that there have been no unpredicted emergency shut-downs of regional gas processing capacity or gas transportation capacity. If documentation can not be provided for a period, a value of zero for this parameter must be applied for this period when determining the emission reductions ex-post. If there are any unpredicted emergency events, the parameter value should be set to zero on a daily basis as long as there is a shut-down during the respective calendar day irrespective of the exact duration of the shut-down. This is a conservative approach.*
D.1.1.3 – 5 *D.1.3.1 - 5*	*Low (+/-1%)*	*This parameter is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80. As a quality control measure, the parameter value can only be set to the monitored value for the purpose of determining the emission reductions if it can be documented through signed statements from the operating companies that there have been no unpredicted emergency shut-downs of regional gas processing capacity or gas transportation capacity. If documentation can not be provided for a period, a value of zero for this parameter must be applied for this period when determining the emission reductions ex-post. If there are any unpredicted emergency events, the parameter value should be set to zero on a daily basis as long as there is a shut-down during the respective calendar day irrespective of the exact duration of the shut-down. This is a conservative approach.*
D.1.1.3 - 6	*Low (+/- 1 %)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80.*
D.1.1.3 – 7	*Low (+/-1%)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80.*
D.1.1.3 – 8	*Low (+/-1%)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80.*
D.1.1.3 – 9	*Low (+/-1%)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80.*
D.1.1.3 - 10	*Low (+/-1%)*	*The data is continuously monitored from the flow meter and controlled by electronic systems. Calibration and maintenance are executed according to national and manufacturer norms. Accuracy determined by GOST 8.401-80.*

D.1.1.3 - 11	*Medium*	*The gas is sampled once per week and is analyzed by a regional laboratory. Laboratory procedures, norms, certifications and standards are within national regulations. 3rd party monitoring report every month. Data could be compared with historical records.*
D.1.1.3 – 12	*Medium*	*The gas is sampled once per week and is analyzed by a regional laboratory. Laboratory procedures, norms, certifications and standards are within national regulations. 3rd party monitoring report every month. Data could be compared with historical records.*
D.1.1.3 – 13	*Medium*	*The gas is sampled once per week and is analyzed by a regional laboratory. Laboratory procedures, norms, certifications and standards are within national regulations. 3rd party monitoring report every month. Data could be compared with historical records.*
D.1.1.3 – 14	*Medium*	*The gas is sampled once per week and is analyzed by a regional laboratory. Laboratory procedures, norms, certifications and standards are within national regulations. 3rd party monitoring report every month. Data could be compared with historical records.*
D.1.1.3 – 15	*Medium*	*The gas is sampled once per week and is analyzed by a regional laboratory. Laboratory procedures, norms, certifications and standards are within national regulations. 3rd party monitoring report every month. Data could be compared with historical records.*
D.1.1.3 – 16	*Medium*	*The drop-out precipitate is sampled weekly and analyzed by a regional laboratory at regular intervals according to a variety of GOST standards. 3rd party reporting every month. Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.1.3 – 17	*Medium*	*The drop-out precipitate is sampled weekly and is analyzed by a regional laboratory at regular intervals according to a variety of GOST standards. 3rd party reporting every month. Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.1.3 – 18	*Medium*	*The drop-out precipitate is sampled weekly and is analyzed by a regional laboratory at regular intervals according to a variety of GOST standards. 3rd party reporting every month Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.1.3 – 19	*Medium*	*The drop-out precipitate is sampled weekly and is analyzed by a regional laboratory at regular intervals according to a variety of GOST standards. 3rd party reporting every month Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.1.3 - 20	*Medium*	*The drop-out precipitate is sampled weekly and is analyzed by a regional laboratory at regular intervals according to a variety of GOST standards. 3rd party reporting every month Laboratory procedures, norms, certifications and standards are within national regulations.*
D.1.3.1 – 8	*Medium*	*This parameter is determined ex-ante based on the historical average energy consumption per 000 m^3 gas processed in the downstream gas processing plant with the highest energy intensity, specified in kWh/000m^3. This is a conservative estimate.*

Based on the uncertainty levels specified in the Table above, a materiality assessment for each input to final calculated emission reductions within the PDD is carried out. The materiality assessment is based on the sensitivity of the expanded emission reduction equation with respect to variations in single parameters. The expanded emission reduction equation can be specified as:

(9)
$$ER_y = \frac{44}{12} \cdot \frac{1}{1000} \cdot \sum_i (V_{Cgas,i,y} \cdot w_{carbon,Cgas,i,y} + V_{Cpre,i,y} \cdot w_{carbon,Cpre,i,y}) - (\sum_i EC_{PJ,i,y} + \sum_i V_{Cgas,i,y} \cdot EI_{GPP,y} \cdot \frac{1}{1000}) \cdot EF_{grid,y} \cdot (1 + TDL_y)$$

Where:

$V_{Cgas,i,y}$	Volume of the gas entering the gas pipeline from VCS *i* measured at point C_{gas} in Figure 4 during the period y, in m^3
$V_{Cpre,i,y}$	Volume of precipitate entering the oil pipeline measured from VCS *i* at point C_{pre} in Figure 4 during the period y, in m^3
$w_{carbon,Cgas,i,y}$	Average carbon content of gas from VCS *i* measured at point C_{gas} in Figure 4, in kgC/m^3
$w_{carbon,Cpre,i,y}$	Average carbon content of precipitate from VCS *i* measured at point C_{pre} in Figure 4, in kgC/m^3
$PE_{CO2,elec,y}$	CO_2 emissions due to the use of electricity for the recovery, compression and transportation of APG during the period y, in tCO2e
$EC_{PJ,i,y}$	Quantity of electricity consumed at VCS *i* during the period y (MWh)
$EF_{grid,y}$	Emission factor for the grid in the period y (tCO_2/MWh)
TDL_y	Average technical transmission and distribution losses in the grid in the period y for the voltage level at which electricity is obtained from the grid at the project site
$EI_{GPP,y}$	Electricity consumption per m^3 gas processed in the most energy intensive GPP in the region, in kWh/000m^3

Based on the expanded emission reduction equation, the total uncertainty of the emission reduction calculation can be estimated (year 2010 used for analysis):

Input:	Value:	Value + 5%	ER (+5%):	Difference:	Sensitivity (S):	%	U_{95}	U_{95} * S	$(U_{95} * S)^2$
$V_{Cgas,VCS-28,y}$	12 600 000	13 230 000	227 423	1 757	0,0078	0,78 %	1,00 %	7,79E-05	6,06E-09
$V_{Cgas,VCS-39,y}$	25 200 000	26 460 000	228 307	2 641	0,0117	1,17 %	1,00 %	1,17E-04	1,37E-08
$V_{Cgas,VCS-Mykhpay,y}$	18 000 000	18 900 000	228 065	2 399	0,0106	1,06 %	1,00 %	1,06E-04	1,13E-08
$V_{Cgas,VCS-26,y}$	25 200 000	26 460 000	228 531	2 865	0,0127	1,27 %	1,00 %	1,27E-04	1,61E-08
$V_{Cgas,VCS-5,y}$	9 000 000	9 450 000	226 785	1 119	0,0050	0,50 %	1,00 %	4,96E-05	2,46E-09
$V_{Cpre,VCS-28,y}$	317 606	333 487	225 848	182	0,0008	0,08 %	1,00 %	8,08E-06	6,53E-11
$V_{Cpre,VCS-39,y}$	223 240	234 402	225 794	128	0,0006	0,06 %	1,00 %	5,68E-06	3,22E-11
$V_{Cpre,VCS-Mykhpay,y}$	707 661	743 044	226 073	407	0,0018	0,18 %	1,00 %	1,80E-05	3,25E-10
$V_{Cpre,VCS-26,y}$	501 750	526 837	225 954	288	0,0013	0,13 %	1,00 %	1,28E-05	1,63E-10

$V_{Cpre,VCS-5,y}$	116 410	122 230	225 733	67	0,0003	0,03 %	1,00 %	2,95E-06	8,72E-12
$w_{carbon,Cgas,VCS-28,y}$	0,812	0,852	227 541	1 875	0,0083	0,83 %	1,50 %	1,25E-04	1,55E-08
$w_{carbon,Cgas,VCS-39,y}$	0,623	0,654	228 542	2 876	0,0127	1,27 %	1,50 %	1,91E-04	3,66E-08
$w_{carbon,Cgas,VCS-Mykhpay,y}$	0,778	0,817	228 233	2 567	0,0114	1,14 %	1,50 %	1,71E-04	2,91E-08
$w_{carbon,Cgas,VCS-26,y}$	0,671	0,705	228 767	3 101	0,0137	1,37 %	1,50 %	2,06E-04	4,25E-08
$w_{carbon,Cgas,VCS-5,y}$	0,729	0,766	226 869	1 203	0,0053	0,53 %	1,50 %	8,00E-05	6,39E-09
$w_{carbon,Cpre,VCS-28,y}$	3,136	3,293	225 848	182	0,0008	0,08 %	1,50 %	1,21E-05	1,47E-10
$w_{carbon,Cpre,VCS-39,y}$	3,137	3,293	225 794	128	0,0006	0,06 %	1,50 %	8,51E-06	7,25E-11
$w_{carbon,Cpre,VCS-Mykhpay,y}$	3,137	3,294	226 073	407	0,0018	0,18 %	1,50 %	2,70E-05	7,31E-10
$w_{carbon,Cpre,VCS-26,y}$	3,136	3,293	225 954	288	0,0013	0,13 %	1,50 %	1,92E-05	3,67E-10
$w_{carbon,Cpre,VCS-5,y}$	3,136	3,293	225 733	67	0,0003	0,03 %	1,50 %	4,43E-06	1,96E-11
$EC_{PJ,VCS-28,y}$	2 398	2 518	225 584	82	0,0004	0,04 %	0,25 %	9,09E-07	8,27E-13
$EC_{PJ,VCS-39,y}$	4 796	5 036	225 502	164	0,0007	0,07 %	0,25 %	1,82E-06	3,30E-12
$EC_{PJ,VCS-Mykhpay,y}$	2 398	2 518	225 584	82	0,0004	0,04 %	0,25 %	9,09E-07	8,27E-13
$EC_{PJ,VCS-26,y}$	4 796	5 036	225 502	164	0,0007	0,07 %	0,25 %	1,82E-06	3,30E-12
$EC_{PJ,VCS-5,y}$	2 398	2 518	225 584	82	0,0004	0,04 %	0,25 %	9,09E-07	8,27E-13
$EF_{grid,y}$	0,609	0,639	224 252	1 414	0,0063	0,63 %	10,00 %	6,27E-04	3,93E-07
TDL_{y}	12 %	13 %	225 514	152	0,0007	0,07 %	10,00 %	6,73E-05	4,52E-09
$EI_{GPP,y}$	274,1	287,8	224 824	842	0,0037	0,37 %	5,00 %	1,86E-04	3,48E-08

D.3. Please describe the operational and management structure that the project operator will apply in implementing the monitoring plan:

>>

Data collection

Data to be collected for the purposes of monitoring of the JI activity includes parameters described in detail in Section D.1.

The management structure will have the UKG Technical Department of SNG Production Unit (PU) assuring that the data is collected as required. He will report to the UKG Director of SNG PU who has the overall responsibility for the monitoring.

Data collection will be recorded according to the following frequency:

Data variable:	Recording frequency:
$EC_{PJ,i,y}$, $V_{Cgas,i,y}$, $V_{Cpre,i,y}$; total of 3*5 = 15 variables	Continuous monitoring, daily aggregation of data for reporting purposes
$w_{carbon,Cgas,i,y}$, $w_{carbon,Cpre,i,y}$; total of 2*5 = 10 variables	Weekly
$EF_{grid,y}$, TDL_y ; total of 2 variables	Annually
$EI_{GPP,y}$; total of 1 variable	Determined ex-ante

A monthly report will be prepared by the 10th of each subsequent month. The report will be used for QA by the UKG Director of SNG PU, who will undertake all necessary consistency checks with operational and commercial data by the 15th of each subsequent month. The monthly report, following QA procedures, will be sent to Carbon Limits for final QC.

Data quality

For the values that are continuously monitored, the data will be aggregated on a daily basis for the purpose of calculating the emission reductions. Potential outliers should be identified and the variation with respect to the trend explained in the monthly monitoring report.

In case of missing or erroneous daily data for the continuously monitored gas and precipitate flows due to problems with the measurement device(s), the average of the last seven days of measurements can be utilized if the variation in the sample is below a threshold level of 10%. If gas flows does not show a consistent pattern, the day with the lowest reported flow during the last thirty days of reliable data should be utilized as a conservative approach. In all cases where missing data is replaced by trend data or conservative minimum values, it needs to be demonstrated that the physical flows are not affected by the problems with the measurement device(s).

In case of missing data for the weekly monitoring of carbon content of the recovered gas and precipitate, the average of the last four weeks of reliable measurements can be utilized if the variation in the sample is below a threshold level of 10%. If the compositions are not stable, the lowest carbon content measured during the last eight weeks of reliable measurements should be used to replace the missing weekly data as a conservative approach. The monitoring report has to highlight missing data and include a justification of the non-existence of data whenever a missing data entry is replaced according to the procedure above.

Data calculation
The operator will install all necessary meters and assure that a software program is installed so as to record the data and generate the monthly monitoring reports. The monitoring equipment and software will be integral to the newly constructed Vacuum Compressor Stations. The following variables will be calculated for the purpose of determining the emission reductions from the project activity:

1. $EC_{PJ,y}$ (Equation 7)
2. $PE_{CO2,elec,y}$ (Equation 6)
3. PE_y (Equation 3)
4. BE_y (Equation 1)
5. LE_y (Equation 4)
6. ER_y (Equation 8)

In addition, the value(s) of the grid emission factor and the average technical transmission and distribution losses in the grid to apply during period y will be determined on an annual basis as described in Section D.1 and D.2. QA of the calculations will be the responsibility of the UKG Director of SNG PU. A final monthly report will be sent to Carbon Limits for final QC.

Data storage and archiving
All data will be archived electronically and stored by TNK-BP. An electronic copy of all relevant data aggregated on a monthly basis will be sent along with the monthly report to Carbon Limits.

The monthly monitoring reports will be stored at TNK-BP's Nizhnevartovsk office to allow easy access for certification until 2 years after the end of the crediting period.

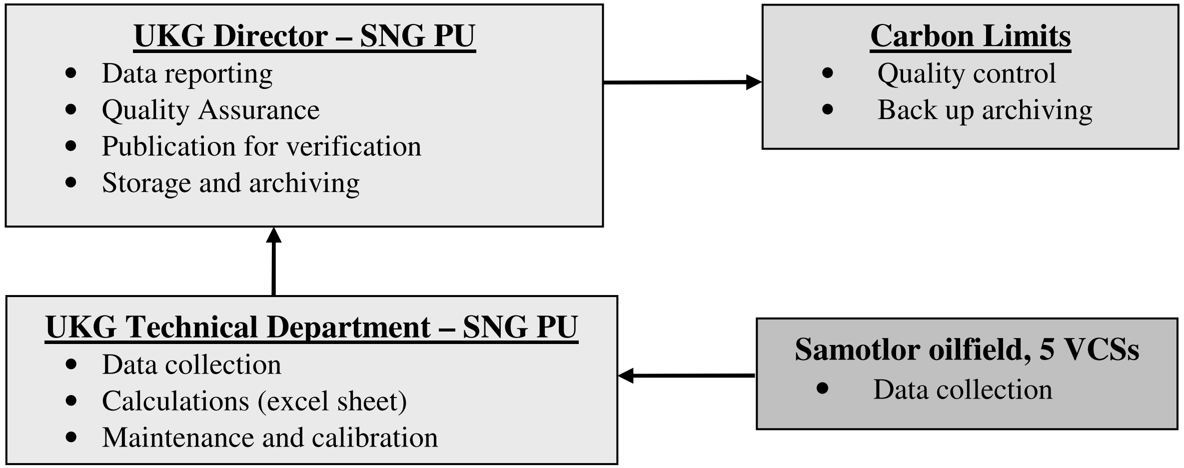
Data verification
The UKG Director of SNG PU will be responsible for making all relevant information available for verification procedures.

Maintenance and calibration
All meters used in this project activity will be of international standards and will be maintained as discussed in the monitoring plan (see Attachment 3). All data will be of high quality with low levels of uncertainty. There is no significant variation in data quality level or uncertainly level in the variables measured. The standards used are also international standards, and thus are of high quality and low levels of uncertainty.

All flow meters shall be calibrated annually. The responsible person and the date of the last calibration of each flow meter shall be specified in the monthly monitoring report. Gas chromatograph maintenance and routine calibration procedures are determined by the procedures, norms, certifications and standards applied by the 3rd party laboratory. These calibration routines are within national regulations.

An annual report will be sent to Carbon Limits detailing when all relevant monitoring and measurement equipment was last calibrated for quality control.

Management structure for monitoring plan
The management structure will have the UKG Technical Department of SNG PU assuring that the data is collected as required. He will report to the UKG Director of SNG PU at the Headquarters in Nizhnevartovsk. See figure below for schematic overview of responsibilities.



Staff training

Prior to starting up project monitoring, training of relevant staff will be provided as follows:

Relevant staff:	JI related training:
Operational staff	Data collection Maintenance and calibration
UKG Director – SNG PU	Data collection Calculations Maintenance and calibration Data reporting
Headquarter staff Nizhnevartovsk	Quality Assurance Data reporting Storage and archiving Publication for verification

D.4. Name of person(s)/entity(ies) establishing the monitoring plan:

>>
Carbon Limits is the entity establishing the monitoring plan and participating in the project as JI developer. The monitoring plan was finalized November 19, 2008. The person in charge of its development is:

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SECTION E. Estimation of greenhouse gas emission reductions

E.1. Estimated project emissions:

>>

Project emissions are estimated to be:

Electricity imported from the regional grid will be consumed to operate the equipment installed as part of the project activity (i.e. the VCSs). The electricity is taken form the Khanty-Manskiysk regional grid, and the corresponding emissions are taken into account as project emissions.

The project emissions from consumption of electricity are estimated to be:

Year:	$\sum_i EG_{PJ,i,y}$ (MWh)	$EF_{grid,y}$ (tCO_{2e}/MWh)	TDL_y (%)	$PE_{CO2,gas,y}$ (tCO_{2e})
2009 (Q2-Q4)	12,590	0.609	12.0%	8,587
2010	16,786	0.609	12.0%	11,449
2011	16,786	0.609	12.0%	11,449
2012	16,786	0.609	12.0%	11,449
2013	16,786	0.609	12.0%	11,449
2014	16,786	0.609	12.0%	11,449
2015	16,786	0.609	12.0%	11,449
2016	16,786	0.609	12.0%	11,449
2017	16,786	0.609	12.0%	11,449
2018	16,786	0.609	12.0%	11,449
2019 (Q1)	4,197	0.609	12.0%	2,862

Based on the discussion in Section B.1, there are no other sources of project emissions. The emissions from consumption of electricity are thus equivalent to the project emissions.

E.2. Estimated leakage:

>>

Leakage emissions are estimated to be:

Utilizing the principle of conservatism, the emissions from consumption of electricity for downstream processing of the recovered gas is included as a source of potential leakage emissions. These emissions are quantified by assuming that all the recovered gas is processed in the regional gas processing plant (physically linked to the Samotlor oil field) with the highest historical electricity consumption per m^3 of gas processed, as shown in Equation 9 in Section D.1.3.2.

The leakage emissions from the project activity are estimated to be:

Year:	$\sum_i V_{Cgas,i,y}$ (m^3)	$EI_{GPP,y}$ (kWh/000m^3)	$EF_{grid,y}$ (tCO_{2e}/MWh)	TDL_y (%)	LE_y (tCO_{2e})
2009 (Q2-Q4)	67,500,000	274.1	0.609	12.0%	12,620
2010	90,000,000	274.1	0.609	12.0%	16,826
2011	90,000,000	274.1	0.609	12.0%	16,826
2012	90,000,000	274.1	0.609	12.0%	16,826

2013	90,000,000	274.1	0.609	12.0%	16,826
2014	90,000,000	274.1	0.609	12.0%	16,826
2015	90,000,000	274.1	0.609	12.0%	16,826
2016	90,000,000	274.1	0.609	12.0%	16,826
2017	90,000,000	274.1	0.609	12.0%	16,826
2018	90,000,000	274.1	0.609	12.0%	16,826
2019 (Q1)	22,500,000	274.1	0.609	12.0%	4,207

E.3. The sum of E.1. and E.2.:

>>

The sum of E.1. and E.2. is summarized below:

Year:	$PE_y = PE_{CO2,elec,y}$ **(tCO_{2e})**	LE_y **(tCO_{2e})**	$PE_y + LE_y$ **(tCO_{2e})**
2009 (Q2-Q4)	8,587	12,620	21,207
2010	11,449	16,826	28,276
2011	11,449	16,826	28,276
2012	11,449	16,826	28,276
2013	11,449	16,826	28,276
2014	11,449	16,826	28,276
2015	11,449	16,826	28,276
2016	11,449	16,826	28,276
2017	11,449	16,826	28,276
2018	11,449	16,826	28,276
2019 (Q1)	2,862	4,207	7,069

E.4. Estimated baseline emissions:

>>

Baseline emissions are estimated to be:

The baseline emissions are calculated according to Equation 1, and are expected to be:

Year:	$\sum_i V_{Cgas,i,y} \cdot w_{carbon,Cgas,i,y}$ **(kgC)**	$\sum_i V_{Cpre,i,y} \cdot w_{carbon,Cpre,i,y}$ **(kgC)**	BE_y **(tCO_{2e})**
2009 (Q2-Q4)	47,551,251	4,391,295	190,456
2010	63,401,688	5,855,060	253,941
2011	63,401,688	5,855,060	253,941
2012	63,401,688	5,855,060	253,941
2013	63,401,688	5,855,060	253,941
2014	63,401,688	5,855,060	253,941
2015	63,401,688	5,855,060	253,941
2016	63,401,688	5,855,060	253,941
2017	63,401,688	5,855,060	253,941
2018	63,401,688	5,855,060	253,941
2019 (Q1)	15,850,417	1,463,765	63,485

Further information about the calculation of baseline emissions can be found in Attachment 2.

E.5. Difference between E.4. and E.3. representing the emission reductions of the project:

>>
The ex-ante estimation of emission reductions can be summarized as:

Year:	BE_y (tCO_{2e})	$PE_y + LE_y$ (tCO_{2e})	ER_y (tCO_{2e})
2009 (Q2-Q4)	190,456	21,207	169,249
2010	253,941	28,276	225,666
2011	253,941	28,276	225,666
2012	253,941	28,276	225,666
2013	253,941	28,276	225,666
2014	253,941	28,276	225,666
2015	253,941	28,276	225,666
2016	253,941	28,276	225,666
2017	253,941	28,276	225,666
2018	253,941	28,276	225,666
2019 (Q1)	63,485	7,069	56,416

Further information about the calculation of emission reductions can be found in Attachment 2.

E.6. Table providing values obtained when applying formulae above:

>>

Year	Estimation of project activity emissions (tonnes of CO_{2e})	Estimation of baseline emissions (tonnes of CO_{2e})	Estimation of leakage (tonnes of CO_{2e})	Estimation of overall emission reductions (tonnes of CO_{2e})
2009 (Q2-Q4)	8,587	190,456	12,620	169,249
2010	11,449	253,941	16,826	225,666
2011	11,449	253,941	16,826	225,666
2012	11,449	253,941	16,826	225,666
2013	11,449	253,941	16,826	225,666
2014	11,449	253,941	16,826	225,666
2015	11,449	253,941	16,826	225,666
2016	11,449	253,941	16,826	225,666
2017	11,449	253,941	16,826	225,666
2018	11,449	253,941	16,826	225,666
2019 (Q1)	2,862	63,485	4,207	56,416
Total 10 yr crediting period	**114,494**	**2,539,410**	**168,262**	**2,256,657**

SECTION F. Environmental impacts

F.1. Documentation on the analysis of the environmental impacts of the project, including transboundary impacts, in accordance with procedures as determined by the host Party:

>>
The environmental review stage is mandatory to obtain a construction permit from the public oversight authorities. An operating permit will be obtained before start of operation. The provisions of the national

legislation (Federal Law on Environmental Reviews (1995); Federal Law on Environmental Protection (1991); Ordinance on the Environmental Impact Assessment in the Russian Federation (1994), as well as other relevant national regulations) were enforced before the Russian State Expertise provided its positive conclusion of the project activity.

As part of getting State approvals for the proposed JI project, TNK-BP have documented the environmental impacts of the project as part of the document pack submitted to the Russian state expertise in accordance to the Russian guidelines for this type of procedure, i.e. OVOS (environmental impact assessment) and OOS (defence of the environment). These can be made available for validation if necessary.

F.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to supporting documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

>>
The project participants do not consider the environmental impacts to be significant, and a positive approval from the Russian state expertise of the project documentation pack has been obtained and provided to the DOE for validation. It should be noted that the project activity occurs in a brownfield site where large amounts of energy infrastructure and operations have existed for decades.

SECTION G. Stakeholders' comments

G.1. Information on stakeholders' comments on the project, as appropriate:

>>
As the project activity is taking place within a heavily developed brownfield site, there has been no formal stakeholder consultation for the proposed JI project activity as this is not required by the Russian authorities. Local stakeholders (e.g. site workers and suppliers) have however been informed throughout the development of the project and have been invited to provide comments on the project through the development of the Environmental Impact Assessment (see Section F.1).

Annex 1

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Annex 2

BASELINE INFORMATION

Records of gas utilization within Samotlor oilfield:

The historical gas balance of the Samotlor oilfield has been made available for validation (2005 to 2007). The gas balance demonstrates that APG from the last stages of oil separation is currently being flared at the field.

Gas compositions SNG gas gathering project:

The compositions of the low-pressure associated gas streams recovered at the five Vacuum Compressor Stations (VCSs) that will be constructed as part of the proposed JI project activity can be found below. The compositions utilized as design inputs for the project are determined by the accredited, independent physics-chemical laboratory in Department for Gas Compression in Samotlorneftegaz (Attestat No. RU.0001.512886).

Composition	**ВКС-28**	**ВКС-39**	**ВКС-Мыхпай**	**ВКС-26**	**ВКС-5**
Nitrogen	1.97	1.42	1.57	2.39	0.59
Methane	40.74	67.85	41.36	56.55	53.51
Ethane	3.26	3.26	4.24	2.23	3.99
Propane	14.18	9.04	12.68	8.52	13.07
Butanes	19.09	9.27	16.86	12.90	15.65
Pentanes	11.51	4.65	10.52	9.01	7.25
Hexanes	5.63	2.40	7.35	5.15	3.42
Heptanes	2.19	1.27	4.93	2.17	1.61
CO_2	0.98	0.82	0.40	0.46	1.21
O_2	0.43	0.04	0.08	0.62	0.02
Net Calorific Value (MJ/Nm^3)	**53.23**	**40.97**	**53.9**	**45.22**	**47.14**
Carbon Intensity Fuel (kg C/MJ)	**0.0153**	**0.0147**	**0.0151**	**0.0151**	**0.0149**
Carbon Content (kg C/kg)	**0.768**	**0.755**	**0.777**	**0.754**	**0.771**
Mass fraction of methane (kg CH4/kg)	**0.407**	**0.679**	**0.414**	**0.566**	**0.535**

Determination of the regional grid emission factor:

The proposed JI project activity requires supplies of electricity from the grid to operate the five VCSs. In addition, grid electricity is consumed downstream in the regional gas processing plants where the recovered gas will be processed as a result of the project activity.

In order to estimate the emissions from consumption of electricity according to the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption (version 01)" referred to in AM0009 version 03.2, the emission factor for the electricity generation and the relevant transmission and distribution losses must be determined ex-ante. These values will be updated annually during the crediting period for the purpose of determining the emission reductions achieved by the project activity in line with the monitoring procedures.

As the proposed project meets the requirement of Scenario A in the "Tool to calculate baseline, project and/or leakage emissions from electricity consumption (version 01)", i.e. electricity consumption from the grid, it was decided to calculate the combined margin emission factor of the applicable electricity system using the "Tool to calculate the emission factor for an electricity system (version 01.1)" (Option A.1 with $EF_{el,j/k/l,y} = EF_{grid,CM,y}$).

In applying the "Tool to calculate the emission factor for an electricity system (version 01.1)", the following six step procedure was followed:

STEP 1 *Identify the relevant electric power system.*
STEP 2 *Select an operating margin (OM) method.*
STEP 3 *Calculate the operating margin emission factor according to the selected method.*
STEP 4 *Identify the cohort of power units to be included in the build margin (BM).*
STEP 5 *Calculate the build margin emission factor.*
STEP 6 *Calculate the combined margin (CM) emissions factor.*

The analysis carried out in each of the steps is explained below:

STEP 1: Identify the relevant electric power system

Russian United Energy System consists of seven Regional Grids (Consolidated Energy Systems) dispatching by single service (System Operator). Each CES comprises of some local energy systems which amount are varied around 10. Each CES operates by its own dispatcher (operational and dispatching bureau) strongly regulating all energy flows (generation, consumption, export and import). The Ural CES is one of these CESs. Its boundaries are clearly defined as well as all included power capacities and main consumers. All current information of total generation, consumption, export and import is continuously updated on the publically available System Operators web site (http://www.so-cdu.ru/view_doc.aspx?doc_code=OES_630000).

The project activity is located in West Siberia in the Khanty-Manskiysky Autonomous Okrug, and is supplied with electricity by the Tumen Power system. The Tumen power system is a major power complex of Ural United Power System. It delivers power and heat energy to consumers of the Tumen oblast, including two autonomous okrugs: Yamalo-Nenetzkiy and Khanty-Mansiysk. The description of the Tumen power system is based on the official data site of the Tumen power dispatching office[10] and the web pages of the corresponding subsidiaries and dependent companies of RAO "UES of Russia"[11].

The Tumen power system unites ten thermal power plants, with a total installed capacity of more than 11,383 MW, including the following biggest plants:

#	Plant	Installed capacity, MW
1	Surgut plant-1	3,280
2	Surgut plant-2	4,800
3	Urengoi GRES	24
4	Nizhnevartovsk GRES	1,600
5	Tumen HPP-1	472
6	Tumen HPP-2	755
7	Tobolsk HPP	452
	Total	11,383

In line with guidance provided in the "Tool to calculate the emission factor for an electricity system (version 01.1)" the project electricity system is defined by the spatial extent of the power plants that is physically connected by transmission and distribution lines within the Tumen Power System.

Over the year, the Tumen grid system has a net positive export of electricity. In 2006, total electricity generation in thermal power plants within the Tumen electricity system was 74,541 GWh, while total consumption in the same region was 69,968 GWh[12]. Due to the lack of detailed information on temporal variations in imports and exports, the fact that the electricity production exceeds consumption in this region demonstrates that the net import of electricity is zero over a full year. As will be shown in Step 2 below, the simple operating margin method is selected to calculate the grid emission factor based on the quality of publicly available data at the time of validation.

STEP 2: Select an operating margin (OM) method

Within the project electricity system, all power plants/units are essentially of the same type (natural gas fired facilities). All units are dispatched throughout the year, and no units are thus considered to be low-cost/must-run resources. As a result, all the four methods mentioned in the Tool can be used to calculate the OM (including the simple OM method).

Given the data availability for power plants/units within the project electricity system, the simple OM method is selected for the proposed project activity. For the simple OM method, Option A is chosen as the most appropriate:

Option A: The simple OM emission factor is calculated *"based on data on fuel consumption and net electricity generation of each power plant/unit"*.

[10] http://www.ural.so-cdu.ru/tumen_rdu/parameters.php

[11] http://www.rao-ees.ru/en/subcomp/show.cgi?subcomp.htm

[12] http://www.ural.so-cdu.ru/tumen_rdu/parameters.php

The Tool specifies that the emission factor can be calculated using either an *ex-ante* or an *ex-post* option. In this PDD, the *ex-ante* option is selected to estimate the OM. The vintage chosen for calculation is 2005 to 2007, which are the latest years for which statistical data are available at the time of submission. The grid emission factor should be updated *ex-post* on an annual basis following the procedures specified in the latest version of the "Tool to calculate the emission factor for an electricity system" in line with the monitoring plan.

STEP 3: Calculate the OM emission factor according to the selected method

Based on the simple OM method Option A, the OM emission factor is calculated as:

(2-1)
$$EF_{grid,OMsimple,y} = \frac{\sum_{i,m} FC_{i,m,y} \cdot NCV_{i,y} \cdot EF_{CO2,i,y}}{\sum_{m} EG_{m,y}}$$

Where:

$EF_{grid,OMsimple,y}$	Simple operating margin CO_2 emission factor in year y (tCO_2/MWh)
$FC_{i,m,y}$	Amount of fossil fuel type *i* consumed by power plan/unit m in year y (mass or volume unit)
$NCV_{i,y}$	Net Calorific Value (energy content) of fossil fuel type *i* in year y (GJ/mass or volume unit)
$EF_{CO2,i,y}$	CO_2 emission factor of fossil fuel type *i* in year y (tCO_2/GJ)
$EG_{m,y}$	Net electricity generated and delivered to the grid by power plant/unit m in year y (MWh)
m	All power plants/units serving the grid in year y except low-cost/must-run power plants/units
i	All fossil fuel types combusted in power plant/unit m in year y
y	Three most recent years for which data is available at the time of submission of the PDD to the DOE for validation (in this PDD equivalent to 2001 to 2004)

When calculating the OM emission factor, the following data have been used:

Emission factors and Net Calorific Values:
In the power plants/units connected to the project electricity system, natural gas has been utilized for the three most recent years. Some plants operate on non-associated natural gas, while other plants operate on associated petroleum gas.

The CO_2 emission factor of natural gas taken as the IPCC default value at the upper level of the 95 % confidence interval as provided in table 1.4 of Chapter 1 of Vol. 2 (Energy) of the 2006 IPCC Guidelines on National GHG Inventories is 0.0583 tCO_2/GJ. The CO_2 emission factor of the natural gas utilized as a fuel has been set equal to the upper value specified by IPCC for all power plants as a conservative measure to reflect the utilization of processed APG in some power plants.

The Net Calorific Value of natural gas is set to 39.6 MJ/m3[13].

[13] http://www.berr.gov.uk/files/file19273.xls

Fuel consumption:
Data on fuel consumption is not available for all power plants for the last three years. However, the specific fuel consumption specified in g/kWh is available for all plants for at least on of the last three years. For those plants where the specific fuel consumption is available for each of the last three years, the values are very stable. To get a complete dataset, the average value of the available specific fuel consumption data for each power plant (which is an indication of plant efficiency) has been utilized to replace the missing values for the last three years (see Attachment 2 for details). The specific fuel consumptions are multiplied with the generation data for each power plant and year to obtain the amount of fuel equivalent consumed in these plants each of the last three years with available data (2005 to 2007). The amounts of fuel equivalents (in tons) are then converted to m^3 of natural gas utilizing statistics presented by ОГК-1[14].

Electricity generation:
The electricity generation data are taken from the annual reports of the operating companies for the last three years of available data (2005 to 2007). The sources utilized can be found in Attachment 2.

Calculation of OM emission factor:
The data referred to above, presented in detail in Attachment 2, can be utilized to calculate the generation weighted OM emission factor according to Equation 2-1. The results are as following:

OM emission factor:	Calculated value:
$EF_{grid,OMsimple,2005}$	0.6167
$EF_{grid,OMsimple,2006}$	0.6147
$EF_{grid,OMsimple,2007}$	0.6150

STEP 4: Identify the cohort of power units to be included in the build margin (BM)

The sample group of power units *m* used to calculate the build margin consists of either:

a. The set of five power units that have been built most recently, or
b. The set of power capacity additions in the electricity system that comprise 20 % of the system generation (in MWh) and that have been built most recently.

Given the limited number of power plants/units in the project electricity system, option a) is utilized. The finalization dates of the various power plants and the plants included in the build margin are presented in the table below:

Power plant:	Year of commissioning:	Included in Build Margin?
Surgut plant-1	1983	No
Surgut plant-2	1988	Yes
Urengoi GRES	1990-1992	Yes
Nizhnevartovsk GRES	1993-2003	Yes
Tumen HPP-1	1970-2006	Yes
Tumen HPP-2	1990	Yes
Tobolsk HPP	1986	No

[14] http://tools.euroland.com/arinhtml/ru-ogka/2007/ar_eng_2007/ (p.23)

STEP 5: Calculate the build margin emission factor

The build margin is the generation-weighted average emission factor (tCO_2/MWh) of all power units *m* during the most recent year *y* for which power generation data is available, calculated as follows:

(2-2) $$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \cdot EF_{EL,m,y}}{\sum_m EG_{m,y}}$$

Where:

$EF_{grid,BM,y}$	Build margin CO_2 emission factor in year y (tCO_2/MWh)
$EG_{m,y}$	Net quantity of electricity generated and delivered to the grid by power unit m in year y (MWh)
$EF_{EL,m,y}$	CO_2 emission factor of power unit *m* in year y (tCO_2/MWh)
m	Power units included in the build margin
y	Most recent historical year for which power generation data is available

The CO_2 emission factor of each power unit m should be determined analogous to the procedure to determine the simple operating margin, using for y the most recent historical year for which power generation data is available. For year 2007, the emission factor of the five power plants to be included in the build margin is 0.6019 tCO_2/MWh. Detailed calculations can be found in Attachment 2.

STEP 6: Calculate the combined margin emissions factor

The combined margin emissions factor is calculated as follows:

(2-3) $$EF_{grid,CM,y} = EF_{grid,OM,y} \cdot w_{OM} + EF_{grid,BM,y} \cdot w_{OM}$$

Where:

$EF_{grid,OM,y}$	Operating margin CO_2 emission factor in year y (tCO_2/MWh)
$EF_{grid,BM,y}$	Build margin CO_2 emission factor in year y (tCO_2/MWh)
w_{OM}	Weighting of operational margin emission factor (%)
w_{BM}	Weighting of build margin emission factor (%)

According to the guidance presented in the "Tool to calculate the emission factor for an electricity system (version 01.1)", the weights are set to:

$$w_{OM} = 0.5$$
$$w_{BM} = 0.5$$

Applying these weights with the calculated operating- and build margin emission factors, the combined margin emission factor for the last three years of available data (2005 to 2007) has been determined to be 0.6089. See Attachment 2 for data sources and detailed calculations.

Annex 3

MONITORING PLAN

The monitoring report (excel sheet) that will be filled out monthly by UKG Technical Department of SNG, controlled by UKG Director of SNG PU and sent to Carbon Limits head office in Oslo can be found in Attachment 4.

Annex 4

Abbreviations used in PDD

APG	Associated Petroleum Gas
BCM	Billion Cubic Meter
CPF	Central Processing Facility
FWCU	Free Water Knock-out Unit
GHG	Green House Gases
GPP	Gas Processing Plant
HP	High Pressure
JV	Joint Venture
LNG	Liquefied Natural Gas
LP	Low Pressure
MMCM	Million Cubic Meter
NGL	Natural Gas Liquids
NOAA	U.S. National Oceanic and Atmospheric Administration
NPV	Net Present Value

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